Application For
Prevention of Significant Deterioration Permit
For the Desert Rock Energy Facility

Prepared for:

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Desert Rock Energy Facility

Application for
Prevention of Significant Deterioration Permit

Submitted to

U. S. Environmental Protection Agency

Air Division

San Francisco, California

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1.0 INTRODUCTION

1.1 Project Overview

Diné Power Authority (DPA), a Navajo Nation Enterprise, has contracted with Steag Power, LLC (Steag) to develop an electric power generation facility on Navajo Nation trust land. The Desert Rock Energy Facility, the "Project", will further support the Navajo Nation by utilizing the Navajo Nation coal reserves from the nearby mine operated by BHP Billiton. Steag and DPA have a shared vision to develop an environmentally friendly project that efficiently uses the Navajo resources and brings substantial benefits to the Navajo Nation and surrounding communities.

Steag has taken a holistic approach to the development and design of this facility to incorporate high efficiency with effective emission controls. Steag proposes to use their German experience and proprietary knowledge to design and build a state-of-the-art, mine-mouth coal-fired power plant, and at the same time improve environmental protection, efficiency and reliability of large coal-fired power plants. The Project will consist of a green-field power plant that will use two supercritical pulverized coal boilers, paired with steam turbines, and will be designed for a total generation capacity of 1,500 MW (gross). The facility will also include three auxiliary boilers, two emergency diesel generators, two diesel firewater pumps and all of the auxiliary equipment necessary to support the green-field power facility. As will be shown in this application, this equipment will generate substantial power with efficient use of the Navajo Nation coal resource and a minimum of air quality impacts.

The Project will include two dry natural draft Heller cooling tower systems to preserve the critical water resources in the region. Water for plant maintenance will be supplied by the Navajo Nation under a water rights permit. This facility has been designed to optimize the use of water for power generation and to maximize efficiency of the plant operations.

Steag is scheduled to start construction on the first unit in 2005 in order to achieve commercial operation of the first unit in 2008. The construction of the second unit is scheduled to follow the first with less than a one-year lag.

The plant will employ over 200 permanent workers and up to a peak of 3,000 workers during the three years of construction. Workers are expected to come from within rural areas of the Navajo Nation (~10%), most will commute from Farmington or Shiprock (~60%), and the remainder from Gallup and Window Rock (~30%). The Navajo Nation requires preferred employment of local people, thus automatically limiting growth in the area and reducing unemployment.

Since the proposed facility will be a "major source" of criteria air pollutants, Steag is applying for a Prevention of Significant Deterioration (PSD) permit. Because this project will be located on the Navajo Nation, and since the Navajo Nation does not yet have PSD delegation, this application is being submitted to the U. S. Environmental Protection Agency (EPA), in Region IX. Steag and DPA continue to work closely with the Navajo Nation Environmental Protection Agency concerning the Project and this application.

1.2 Facility Classification

There are two major classification criteria for the proposed facility, one related to its industrial character and the other to its potential to emit air contaminants. The designation of the facility under each of these is reviewed below.

1.2.1 Standard Industrial Classification (SIC) Code

The United States government has devised a method for grouping all business activities according to their participation in the national commerce system. The system is based on classifying activities into "major groups" defined by the general character of a business operation. For example, electric, gas, and sanitary services, which include power production, are defined as a major group. Each major group is given a unique two-digit number for identification. Power production activities have been assigned a major group code “49”.

To provide more detailed identification of a particular operation, an additional two-digit code is appended to the major group code. In the case of power generation facilities the two digit code is “11” in order to define the type of production involved. Thus, the Desert Rock Energy Facility is classified under the SIC code system as:

- “Major Group” 49 – “Electric, Gas, and Sanitary Services”
- Electric Services – 4911

The SIC Code system will eventually be replaced by North American Industrial Classification System (NAICS). This system's organization is similar to the SIC codes. Under this system, this facility would be classified under 221112, Fossil Fuel Electric Power Generation.

1.2.2 Air Quality Source Designation

With respect to air quality, new and existing industrial sources are classified as either major or minor sources based on their potential-to-emit (PTE) air contaminants. This classification is also affected in part by whether the area in which the source is located has attained the National Ambient Air Quality Standards (NAAQS)[1] An area is classified as attainment if the ambient air quality concentration for a specific pollutant as measured by a monitor is below the standard concentration level for a set averaging period. The area in which the project is proposed to be located is designated as attainment for all the NAAQS.

[1] Criteria pollutants are those for which EPA has established NAAQS and consist of particulate matter with a nominal aerodynamic diameter of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen dioxide, sulfur dioxide, lead and ozone, which is formed through the photochemical reaction of volatile organic compounds and oxides of nitrogen in the atmosphere.

For most activities, a major source is defined as one that has the potential-to-emit 250 tons per year (tpy) of any regulated air contaminant. For a special group of 28 industrial categories, the EPA has defined the major source emission threshold to be 100 tpy. Steam-Electric Power Generation is one of these special categories. As will be shown in Section 5.0, potential emissions from the proposed facility will exceed the major source thresholds for Oxides of Nitrogen (NO_x), Carbon Monoxide (CO), Particulates (PM/PM_{10}), Volatile Organic Compounds (VOC), Sulfur Dioxide (SO_2), and Hazardous Air Pollutants (HAP). Therefore, the project will be classified as a “major stationary source” of air emissions.

1.3 Document Organization

This application addresses the permitting requirements of the federally mandated program for PSD review (40 CFR 52.21) for a new major source. Section 2.0 provides an overview of the proposed project and the processes covered by this application. Section 3.0 discusses the regulatory setting for the project. Section 4.0 provides the control technology evaluation for those pollutants subject to PSD review. Section 5.0 presents the emissions anticipated from the operation of the facility. Section 6.0 presents a detailed discussion of the dispersion modeling methodology and applicable standards to which the predicted impacts, including from a cumulative source assessment, are compared. Finally Section 7.0 references the regulatory and technical citations used in the document.

Attached to this application are:

1) a description of alternative combustion technologies,
2) supplemental information to the BACT analysis,
3) performance data and emissions calculations,
4) the modeling protocol
5) modeling files on a CD, and supplementary modeling results;
6) documentation of source information used for the cumulative analysis
7) a description of refinements used for determining regional haze impacts;
8) a threatened and endangered species analysis for the power generation site, and
9) a historical preservation act analysis for the site.

1.4 Applicant Information

Listed below are the applicant's primary points of contact and the address and phone number where they can be reached. This PSD application has been prepared by a third party under the direction of Steag Power, LLC and contacts have been included for the permitting consultant as well.

Applicant's address

Corporate Office	Steag Power, LLC Three Riverway, Suite 1100 Houston, Texas 77056
Desert Rock Energy Facility Site	Central San Juan County, New Mexico Navajo Nation Territory

Applicant's Contact

Corporate Environmental Contact	Gus Eghneim, Ph.D., P.E. Director, Environmental Affairs Gus.eghneim@steagpower.com Telephone (713) 499-1132 FAX (713) 499-1167

Consultant's Contacts

Permitting Consultant	William Campbell, III, P.E. Project Manager ENSR International 4600 Park Road, Suite 300 Charlotte, NC 28209 Wcampbell@ensr.com Telephone (704) 529-1755 FAX (704) 529-1756
Permitting Consultant	Sara Head Air Permitting Manager ENSR International 1220 Avenida Acaso Camarillo, CA 93012-8738 Shead@ensr.com Telephone (805) 388-3775 x227 FAX (805) 388-3577

2.0 PROPOSED PROJECT

Steag, under a development agreement with the Navajo Nation's Diné Power Authority, is proposing to develop a technologically advanced, mine-mouth coal-fired power plant. The power plant will be erected in the Northwestern Area of New Mexico adjacent to Navajo Nation coal reserves at a operating mine of BHP Billiton, one of the largest domestic suppliers of low-sulfur coal. The power plant will be a supercritical pulverized coal type and is designed for a total nominal generation capacity of 1,500 MW (gross), composed of two units of 750 MW (gross) and 683 MW (net) each. Use of a once through, supercritical steam cycle and other design features will enable this plant of be one of the most efficient dry cooled steam electric plants ever built in the United States with a net efficiency greater than 40% based on the lower heating value of the fuel. State-of-the-art emission controls will be used to minimize emissions of potential air pollutants. Water consumption will be minimized by using a Heller system, dry natural draft cooling tower. Solid wastes produced by combustion of the coal and the air pollution control system will be returned to the mine.

2.1 Project Location

The Desert Rock Energy Facility will be located on a ~580 acre site close to the Navajo Nation coal reserves leased to BHP Billiton in Northwest New Mexico. The site location is ~25 miles Southwest of Farmington, San Juan County, New Mexico in the Navajo Indian Reservation as shown in Figure 2-1. The site can be accessed via Highway 249 from Shiprock, NM and further on Indian Service Routes to be improved for transportation purposes by grading, drainage and paving. No transportation is currently available by railway.

Figure 2-1 General View – Farmington Region

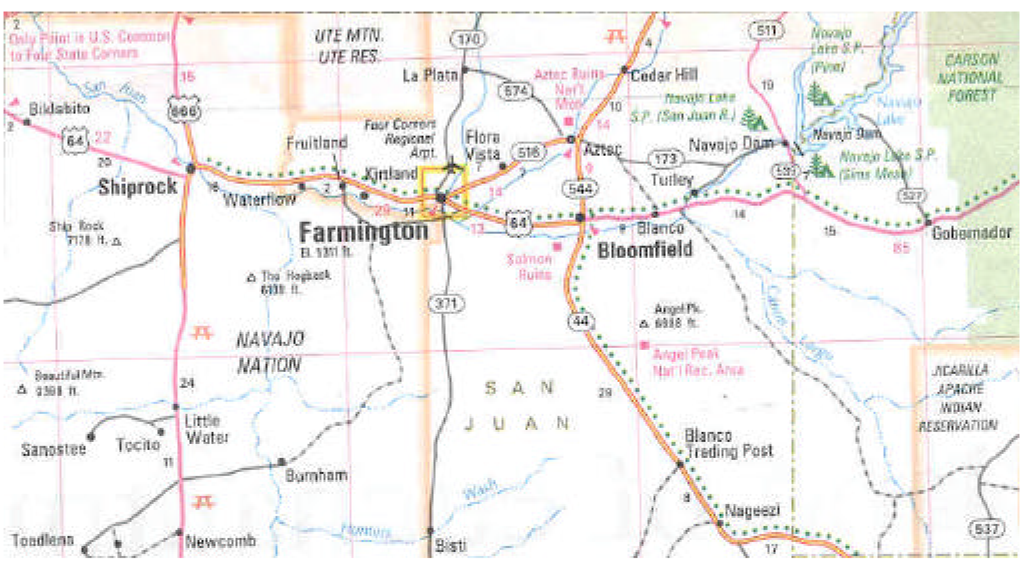

Figure 2-2 shows the location of the transmission line routes for the Desert Rock Energy Facility, as well as other power plants in the area. Figure 2-3 provides an impression of the project site. The project site can be characterized by open flat prairie. Chaco River is a slow creek with extended wetlands, which may fall dry during summer season.

2.2 Desert Rock Energy Facility Combustion Technology Selection

Four technologies may be considered for a new large coal fueled power plant as listed below:

- Pulverized Coal Combustion (sub-critical steam production)
- Pulverized Coal Combustion (supercritical steam production)
- Circulating Fluidized Bed (CFB) Combustion
- Integrated Gasification Combined Cycle (IGCC)

These four technologies are discussed further in Attachment 1. The choice of technology for a specific project is affected by many variables including, but not limited to, project location, the size of the project, fuel cost and source or sources, land or space availability, the developer's experience with a technology, electricity markets and many other factors. These variables affect the capital cost, operating cost, technological risks, and environmental impacts in different ways for each specific project. Key factors that affected the decision to select a pulverized coal-fired supercritical boiler for the Desert Rock Energy Facility are highlighted in this section.

Steag, under a development agreement with DPA, is proposing a green-field, stand alone 1,500 MW gross power plant at a mine-mouth site in New Mexico using two large, high efficiency, supercritical pulverized coal-fired boilers. Economies of scale are favorable for these large units and the fuel to electricity efficiency of above 40%, including dry cooling, is very high. The plant will have a single source of fuel, the adjacent mine, so fuel flexibility is not critical. Air pollutant emissions can be controlled to very low levels using state-of-the-art emission controls. Solid wastes generated by combustion of the coal and the air pollution control system can be returned to the mine.

Sub-critical pulverized coal-fired boilers would be similar to the planned supercritical pulverized coal-fired boilers except that the fuel to electricity efficiency would be significantly lower. At a typical efficiency of about 30 to 35% a sub-critical pulverized coal-fired boiler would burn 15 to 20% more fuel than a supercritical boiler to produce the same amount of electricity. It would also produce 15 to 20% more ash for the same output. Steag's evaluation favored a supercritical boiler, in part, due to the high efficiency and lower emissions associated with burning less fuel. Therefore, the option to install a sub-critical boiler was rejected.

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Figure 2-2 Location of the Desert Rock Energy Facility in Relation to Other Generating Stations in the Area

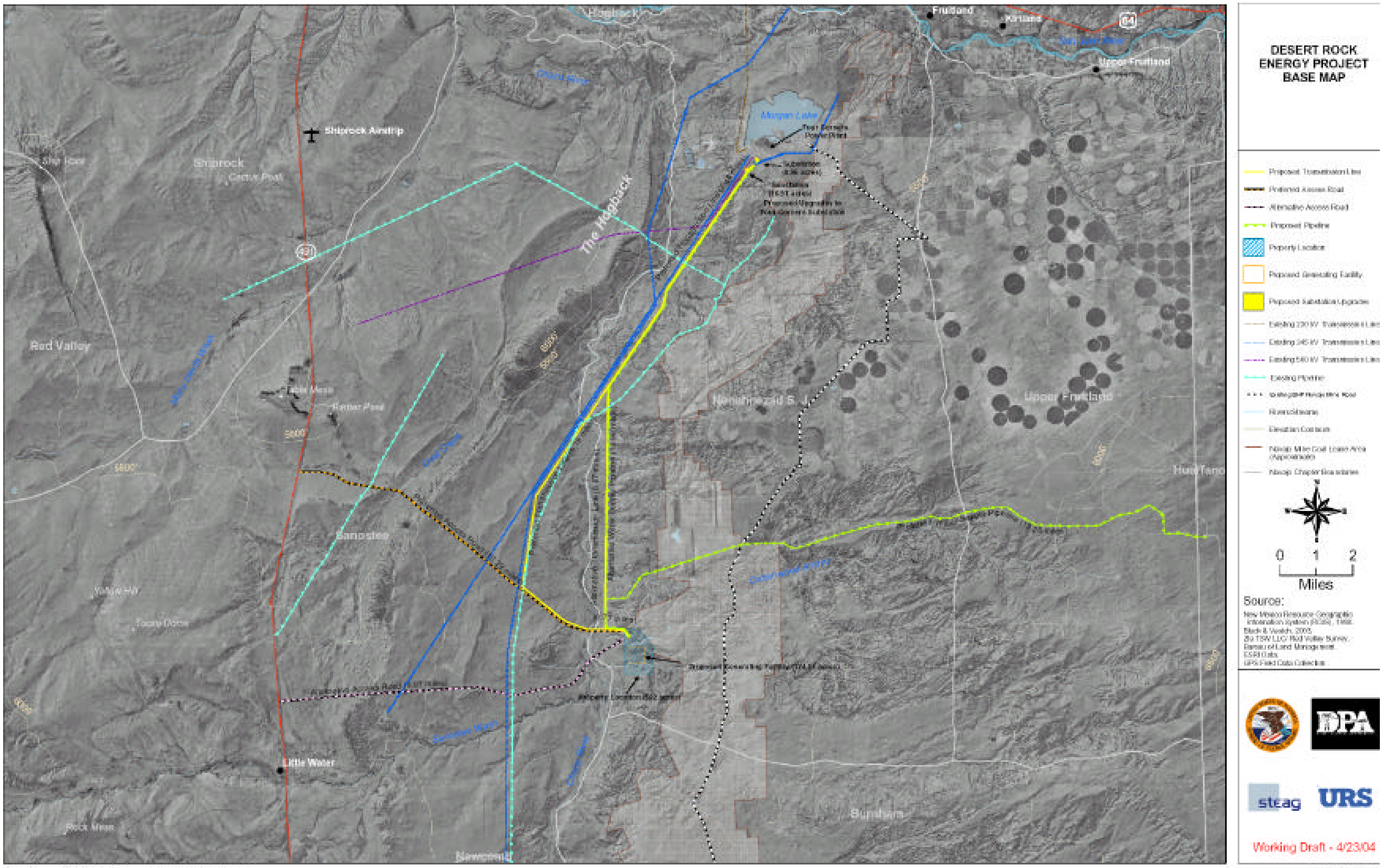


Figure 2-3 Local Terrain in the Power Plant Site Area

CFBs are not currently operating in supercritical steam cycles so efficiencies are similar to sub-critical pulverized coal-fired boilers. Although a possible advantage of a CFB is fuel flexibility, this is not a factor for the planned mine mouth power project. Limitations on the size of a CFB boiler would require 4 to 6 CFB boilers instead of the planned 2 PC boilers. For the planned project, two supercritical PC boilers are favored over the CFB option.

IGCC is a developing technology that may offer high thermal efficiencies. The three projects built to date in the U.S. have been demonstration projects partially funded by the Department of Energy. No coal based IGCC plants have been built in the U.S. without government funding. Steag Encotec GmbH, a 100% owned subsidiary of Steag AG, has designed, built and operated IGCC systems in Europe with limited success. Steag AG, the parent company of both Steag Power (the development arm in the U.S.) and Steag Encotec (the engineering arm in Germany), is believed to have operated the very first IGCC unit. Steag AG operated this 170 MW IGCC plant in Europe in the 1970s to experiment with the long-term reliability and availability of the unit. They found the IGCC technology to be a very complex and capital intensive technology that is subject to availability problems. Although IGCC is cost competitive in many worldwide locations when using petroleum residual feed stocks, it is not economically competitive when using coal. IGCC is not a pollution free technology. Instead, emissions from an IGCC plant are well controlled by a complex and expensive array of gas cleaning systems that are required to clean the syngas in order to protect the gas turbine. IGCC is not currently an available or commercially viable technology for a 1,500 MW commercial coal-fired power plant. Therefore, the IGCC option was rejected for the planned project.

Table 2-1 presents a comparison of the performance data for the four coal combustion technologies identified above. Pulverized Coal combustion and IGCC have virtually no inherent emission control and must rely solely on back end add-on pollution control equipment. Circulating fluidized beds are inherently lower emitting combustion processes, and this technology actually prevents SO_2 and NO_x from being emitted from the process in the first place. The control of SO_2 for CFB includes adsorbent injection, which is also necessary to burn the coal in suspension – it is therefore inherent to the process itself. Similarly, staged combustion, low temperature combustion and ammonia injection directly into the solids separation stage of the CFB prevents NO_x from being emitted prior to the air pollution control train, and is also inherent to the technology. In order to permit a new coal-fired generation facility using any coal combustion technology will require best available emission control levels that are as low or lower than the current state-of-the-art – hence, "Clean Coal Technology".

Table 2-1
Range of Emissions Control from Coal Combustion Technologies

Coal Technology	Efficiency (%)	%NO_x Controlled	%SO_2 Removed
Sub-critical PC	34 to 37	90% (add-on)	92-96% (add-on)
Supercritical PC	39 to 45	90% (add-on)	92-96% (add-on)
CFB [1]	34 to 37	50 to 80%	75 to 92%
IGCC	38 to 45 [2]	70 to 90%	90 to 99.9%

1. Dependent on sorbent activity and injection rate.
2. Currently operating plants do not achieve 45% efficiency.
Source: World Bank.

2.3 Desert Rock Energy Facility Diagrams

A plot plan for the facility is shown in Figure 2-4, a side view is shown in Figure 2-5, and a process flow diagram is shown in Figure 2-6.

2.4 Process Equipment Description

This section describes the major equipment and components of the Desert Rock Energy Facility.

2.4.1 Coal Handling

Low sulfur blended coal from Navajo Nation at the BHP Billiton New Mexico Coal mine will be delivered to the project site by conveyor. A passive or inactive coal pile will be built on the site for emergency purposes. Normal preparation, blending (if necessary), and storage will be handled by the mine on their property. The conveyor from the BHP Billiton mine will move coal through a series of enclosed transfer houses where the coal will drop onto conveyors for transport to bunkers provided for each boiler. From the bunkers, coal is fed through pulverizers to the boilers.

Figure 2-4 Facility Side View of a Boiler Unit at the Proposed Desert Rock Energy Facility

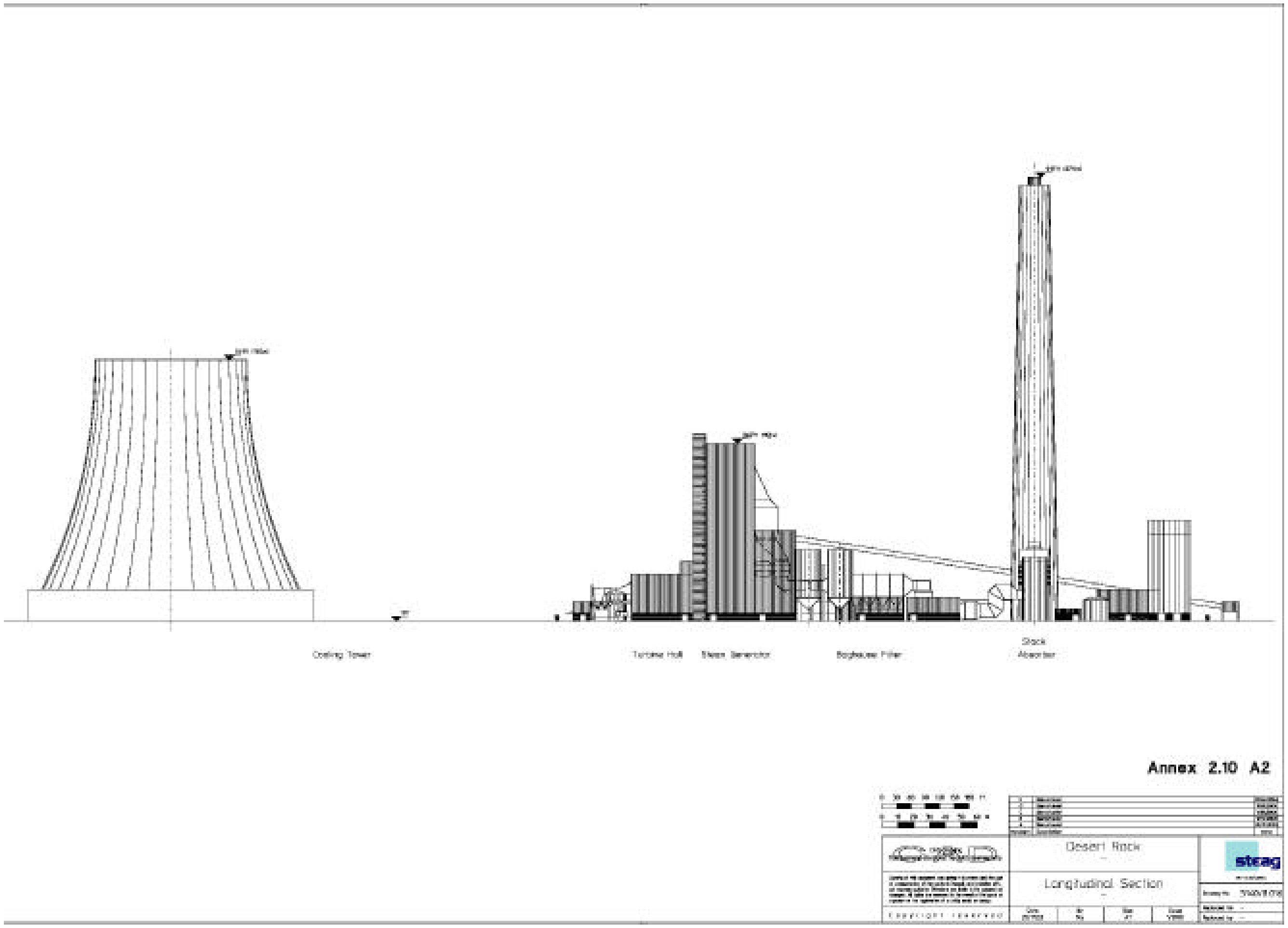


Figure 2-5 Detailed Plot Plan of Boiler Units

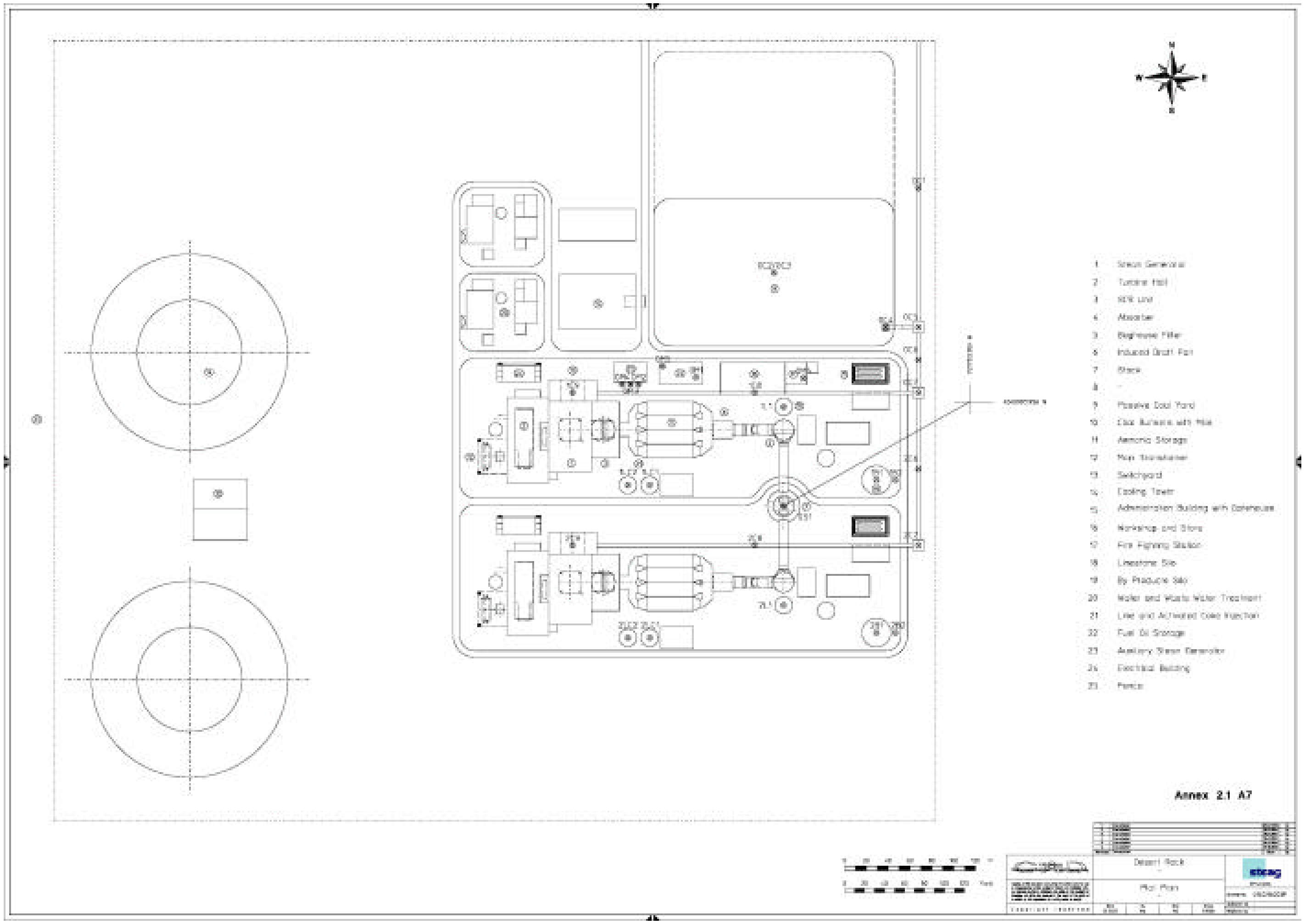
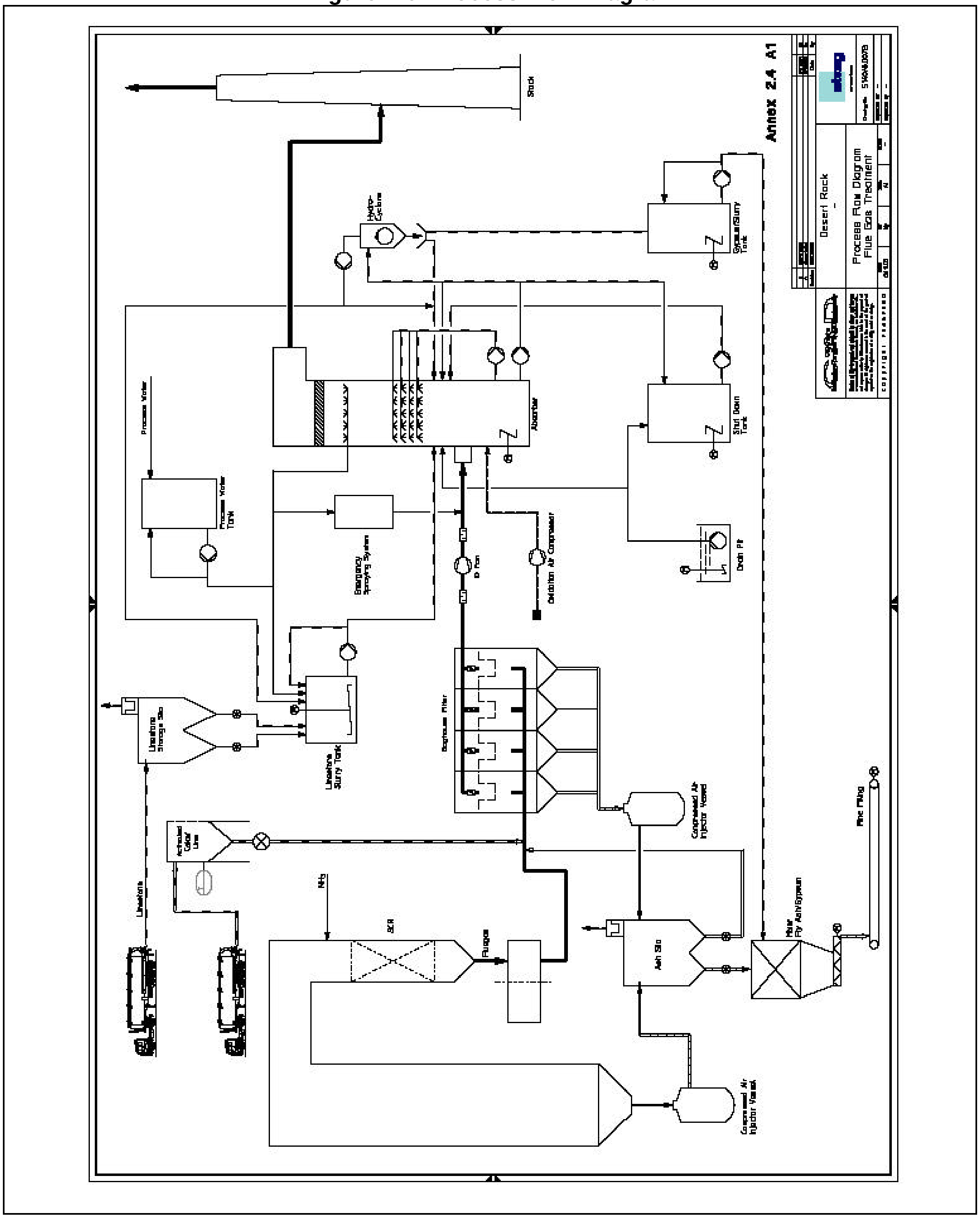


Figure 2-6 Process Flow Diagram



This on-site coal pile will be covered or sealed to prevent emissions and spontaneous combustion. Conveyors are totally enclosed to prevent emissions. Dust suppression, enclosures, or baghouses will be used as appropriate to control emissions from material transfer points and the coal bunkers. Coal specifications are presented in Table 2-2.

Table 2-2
Fuel Data for Main Boilers

	Units	Design Fuel	Fuel Range
1. Fuel quality (coal) proximate analysis			
Higher heating value (HHV)	Btu/lb (kJ/kg)	8,910 (20,725)	8,550 - 9,380 (19,887 - 21,818)
Lower heating value (LHV) or net calorific value	Btu/lb (kJ/kg)	8,479 (19,723)	
Total moisture	%	14.2	13.4 – 15.6
Ash content	%	20.5	17.6 – 23.4
Sulfur	%	0.82	< 1.2
Volatile matter	%	31.7	27.6 – 36
Coal particle size	In	0-2	0-2
Percentage of outsize particle size	%	10	10
Max. coal particle size	In	4	4
2. Ultimate analysis			
Carbon	% wt.	56.38	41.96 – 70.26
Hydrogen	% wt.	2.99	1.81 – 4.29
Oxygen (balance)	% wt.	6.8	2.36 – 15.42
Nitrogen	% wt.	1.00	0.56 – 1.47
Sulfur	% wt.	0.82	0.59 – 0.98
Chlorine	% wt.	0.01	= 0.03
Fluorine	% wt.	0.01	= 0.05
Mercury	Ppm	0.046	0.2

2.4.2 Pulverized Coal-fired Boilers

The power plant will be of the supercritical pulverized coal type and is designed for a total nominal generation capacity of 1,500 MW (gross) divided into two units of 750 MW (gross) and 683 MW (net) each. Each boiler will have a heat input of capacity of approximately 6,800 MMBtu/hr (extreme maximum) and will burn up to 382 tons/hour of coal. In the supercritical cycle, steam is produced at 3,626 psi and 1,112 °F at a rate of 4,636,000 lb/hour. The high-pressure steam is fed through a steam turbine generator to generate electricity and then to a direct contact jet condenser.

Air pollution controls for the pulverized coal-fired boilers will consist of the following:

- Low-NO_x burners and selective catalytic reduction (SCR) to control NO_x emissions;
- Low sulfur coal, hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurization to control SO_2 emissions;
- Hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurization to control acid gas emissions including sulfuric acid mist;
- Activated carbon injection (if needed), hydrated lime injection before a fabric filter, and wet limestone flue gas desulfuriation to control mercury emissions;
- A fabric filter to control particulate emissions; and
- Good combustion to control CO and VOC emissions.

2.4.3 Cooling Towers

A direct contact jet condenser will be used with a Heller dry cooling tower system. In this cooling system, the process steam from the steam turbine is fed to the condenser and condensed by direct cooling with the cooling water coming from the cooling cycle. The blended cooling water and condensate are collected in the hot-well and extracted by circulating water pumps. Approximately 2% of this flow – corresponding to the steam condensed – is fed to the boiler feed water system by condensate pumps. The major part of the flow is returned to the cooling tower for recooling. The cooling duty is performed by the cooling deltas, divided into parallel sectors, where cooling air flow is induced by a natural draft dry cooling tower.

The Heller-type hybrid cooling tower is used to minimize water consumption. When the ambient temperature is below 80 °F, the cooling tower operates like a natural draft dry cooling tower. When the temperature exceeds 80 °F, the facility has the option of applying water oversprays on the heating surfaces inside of the cooling tower to provide additional cooling. This type of cooling tower has no particulate emissions.

2.4.4 Auxiliary Boilers

Three auxiliary steam generators provide auxiliary steam demand during stand still and start up of the main steam generator (auxiliary steam consumers: dearator, atomizing steam for oil firing not a mechanical atomizer in use, steam air heater, turbine seals etc). The auxiliary steam generators are of fire-tube/smoke-tube type (package boilers, shell type). Each auxiliary steam generator has a heat input capacity of 86.4 MMBtu/hour. Emission are controlled by only burning low sulfur (0.05% sulfur) distillate oil, Low-NO_x burners, good combustion, and limiting operation to an average of 1,650 hours/year for the three boilers (equivalent to a total maximum annual fuel use in the three boilers of 142,560 MMBtu/year at full load operation).

2.4.5 Emergency Diesel Generators and Firewater Pumps

There will be two emergency diesel generators with capacities of 1,000 kW and two firewater pumps with capacities of 180 kW. Emission will be controlled by only burning low sulfur (0.05% sulfur) distillate oil, ignition timing retard with turbocharging and aftercooling, good combustion, and limiting normal operation to a maximum of 100 hours/year per engine.

2.4.6 Fuel Oil Supply

Low sulfur distillate oil (0.05% sulfur) will be used for startup of the pulverized coal-fired boilers and operation of three auxiliary boilers. Oil will be delivered to the site by truck, unloaded at one of two unloading stations and stored in a 1.1 million gallon tank.

2.4.7 Limestone Supply

Ground limestone is delivered to the site by trucks and pneumatically conveyed to a limestone storage silo. The silo will be equipped with a baghouse to control PM_{10} emissions. Limestone will be withdrawn from the bottom of the silo by a rotary vane feeder and transported to the limestone slurry tank where it is mixed with water. The limestone slurry will be used in the wet flue gas desulfurization system.

2.4.8 Hydrated Lime and Activated Carbon Supply

Hydrated lime and activated carbon, if needed, will be delivered to the site by trucks and pneumatically conveyed to storage silos. The silos will be equipped with a baghouse to control PM_{10} emissions. Hydrated lime will be injected in the duct prior to the fabric filter to control acid gas emissions. Activated carbon will be injected, if necessary, in the duct prior to the fabric filter to control mercury emissions.

2.4.9 Anhydrous Ammonia Supply

Anhydrous ammonia will be delivered to the site by truck for storage in a pressurized tank. There are no air pollutant emissions from the pressurized storage tanks. The anhydrous ammonia system consists of all equipment required to unload, compress, store, transfer, vaporize, dilute, and convey the ammonia/air mixture into the ammonia injection grid upstream of the selective catalytic reduction system.

2.4.10 Ash Handling

Fly ash will be collected by the main fabric filter. The pulverized coal-fired boiler will generate bottom ash. Fly ash and bottom ash will be mixed in an ash silo. Emissions from the ash silo will be controlled by a fabric filter. Gyspum, with a water content in the 10% to 20% range, will be generated by the wet flue gas desulfurization system. The gypsum fly ash and bottom ash will be mixed together and then transported back to the mine by a conveyor.

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3.0 REGULATORY SETTING

This project will be built on Navajo Nation trust land leased from the Navajo Nation through the U.S. Department of Interior. As a federally recognized tribe, the Navajo Reservation is considered sovereign land and is not subject to the regulations of the State of New Mexico. They are subject to the U.S. Environmental Protection Agency (EPA) regulations as are individual States. Air Permitting for this project will be under the jurisdiction of EPA Region IX, since the majority of the Navajo Nation is located in Arizona. All local regulations will be administered by the Navajo Nation EPA (NN EPA) which have been adopted for the most part from the New Mexico Environmental Department (NMED) regulations. The Navajo Nation has not been delegated authority under the Clean Air Act to issue a Prevention of Significant Deterioration permit by EPA, so the PSD permit will be issued by EPA Region IX. DPA and Steag are continuing to coordinate with NN EPA on the Project.

This section presents a review of the air quality regulatory requirements applicable to the construction and operation of the Desert Rock Energy Facility.

3.1 Ambient Air Quality Standards and Current Attainment Status

National Ambient Air Quality Standards (NAAQS) are established for specific air pollutants based on health effects criteria. The NAAQS for these *criteria* pollutants are expressed as total concentrations of the pollutants in the air to which the general public is exposed. The NAAQS are presented in Table 3-1. The facility will be located near Farmington, San Juan County, New Mexico. This area is part of New Mexico Air Quality Control Region (AQCR) 014. The current air quality of the AQCR, based on actual measurement data, is better than the NAAQS. Thus AQCR 014 is designated as attaining the NAAQS for all criteria pollutants.

Similar to the NAAQS, New Mexico has state ambient air quality standards (NMAAQS). The NMAAQS are defined in Section 20.2.3 NMAC of the New Mexico Air Quality Regulations and are listed in Table 3-2. The current air quality of the AQCR is also better than the NMAAQS.

The Desert Rock Energy Facility will be required to demonstrate that it will neither cause nor contribute to a violation of either the NAAQS or the NMAAQS. The NMAAQS apply only in the area in New Mexico located outside the Navajo Nation.

Major new sources located in attainment areas are required to obtain a PSD permit prior to initiation of construction.

Table 3-1
Ambient Air Quality Standards

Pollutant	Averaging Period[2]	National AAQS[1]	
		Primary	Secondary
SO_2	Annual	80	--[3]
	24-hour	365	--[3]
	3-hour	--[3]	1,300
PM_{10}	Annual	50	50
	24-hour	150	150
$PM_{2.5}$	Annual	15	15
	24-hour	65	65
CO	8-hour	10,000	--[3]
	1-hour	40,000	--[3]
Ozone	1-hour	235	235
	8-hour	157	157
NO_2	Annual	100	100
Lead	3-month	1.5	--[3]

1. All standards in this table are expressed in $\mu g/m^3$.

2. National short-term ambient standards may be exceeded once per year; annual standards may never be exceeded. Ozone standard is attained when the expected number of days of an exceedance is equal to or less than one.

3. No ambient standard for this pollutant and/or averaging period.

Source: 40 CFR 52.21

Table 3-2
New Mexico Ambient Air Quality Standards

Pollutant	Averaging Period	Air Quality Standard
NO_2	Annual[1]	0.050 ppm
	24-hour	0.01 ppm
SO_2	Annual[1]	0.02 ppm
	24-hour	0.10 ppm
TSP	Annual[2]	60 $\mu g/m^3$
	30-day	90 $\mu g/m^3$
	7-day	110 $\mu g/m^3$
	24-hour	150 $\mu g/m^3$
CO	8-hour	8.7 ppm
	1-hour	13.1 ppm
H_2S	1-hour	0.010[3] ppm

1. Arithmetic Mean
2. Geometric mean
3. For the entire State with the exception of Pecos-Permian Basin Intrastate AQCR, no to be exceeded more than once per year.

Source: 20.2.3 NMAC

3.2 Prevention of Significant Deterioration (PSD) Requirements

PSD review applies to specific pollutants for which a project is considered major and the project area is designated as attainment or unclassified with respect to the NAAQS. For a new facility to be subject to PSD review, the project's potential to emit (PTE) must exceed the PSD major source thresholds, which are:

- 100 tpy if the source is one of the 28 named source categories, or
- 250 tpy for all other sources

The Desert Rock Energy Facility is one of the 28 named categories, specifically a fossil fuel fired steam-generating plant with heat input greater than 250 MMBtu/hour. As such, the applicable PSD threshold is 100 tpy. Once it is determined that a pollutant exceeds the PSD major source threshold, additional pollutants will be subject to PSD review if their potential to emit (PTE) exceeds the PSD Significant Emission Rates. Table 3-3 compares the Desert Rock Energy Facility annual PTE with the PSD significant emission rates. As shown in the table, the Desert Rock Energy Facility's PTE is estimated to be greater than the PSD significant emission rates for these PSD pollutants. PSD review and approval will therefore be required for these pollutants.

Table 3-3
Comparison of Desert Rock Energy Facility Annual PTE to the PSD Thresholds

Pollutant	PSD Significant Emission Rate (tpy)	Project PTE [1] (tpy)
CO	100	5,529
NO_x	40	3,325
SO_2	40	3,319
Particulate Matter (TSP/PM)[2]	25	570
PM_{10}[3]	15	1,120
Ozone (VOC)	40	166
Lead	0.6	11.1
Fluorides	3	13.3
Sulfuric Acid Mist (H_2SO_4)	7	221

1. Assumes 95 percent annual capacity factor at full load emissions.
2. PM is defined as filterable particulate matter as measured by EPA Method 5.
3. PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. Because PM_{10} includes condensable particulate matter and PM does not include condensable particulate matter, PM_{10} emissions are higher than PM emissions.

3.2.1 Best Available Control Technology

A PSD source must conduct an analysis to ensure the application of the Best Available Control Technology (BACT), to emissions of pollutants subject to PSD review. Guidelines for the evaluation of BACT can be found in EPA's Cost Control Manual (EPA 1996, 2002) and in the PSD/NSR Workshop Manual (EPA 1990 DRAFT). These guidelines were prepared by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters.

3.2.2 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of existing ambient air quality data in the area to be affected by the proposed project. The definition of existing air quality can be satisfied by air measurement data from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. This condition may be waived if the project would cause an impact less than EPA-specified *de minimis* monitoring levels established by the EPA. The de minimis monitoring levels are listed in Table 3-4.

Table 3-4
PSD *De Minimus* Monitoring Concentrations

Pollutant	Avg. Period	Threshold Concentration ($\mu g/m^3$)
CO	8-hour	575
NO_2	Annual	14
SO_2	24-hour	13
PM_{10}	24-hour	10
O_3	NA	-[1]
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total Reduced Sulfur	1-hour	10
Reduced Sulfur Compounds	1-hour	10
Hydrogen Sulfide	1-hour	0.2
1. Exempt if VOC emissions are less than 100 tpy		

3.2.3 Air Quality Impact Analysis

An air quality impact analysis (AQIA) must be performed for a proposed project subject to PSD review for each pollutant for which the increase in emissions exceeds the de minimis emissions rate. The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing the AQIA. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (EPA 1999). The impact analysis may be limited to only the new source if impacts are below significant impact levels (SILs).

The AQIA is governed by a modeling protocol designed for the specific source type and surrounding dispersion regime. The modeling protocol implemented for this application is included in Attachment 4.

The cumulative incremental air quality impacts to baseline air quality from all PSD sources significantly impacting an area are limited to the PSD increments listed in Table 3-5. In no case, however, can the incremental impacts cause a violation of the NAAQS. PSD Increments are established for PM_{10}, SO_2, and NO_2 for two types of areas, Class I and Class II. Class I areas are those in which the least amount of incremental impact can occur. Class I areas are federally mandated and include specific National Parks, National Forests and Wilderness Areas.

Table 3-5
Allowable PSD Increments and Significant Impact Levels (µg/m^3)

Pollutant	Averaging Time	PSD Increments		Significant Impact Levels
		Class I	Class II	Class II
PM_{10}	Annual Arithmetic Mean	4	17	1
	24-hour Maximum	8	30	5
SO_2	Annual Arithmetic Mean	2	20	1
	24-hour Maximum	5	91	5
	3-hour Maximum	25	512	25
CO	8-hour Maximum	NA	NA	500
	1-hour Maximum	NA	NA	2,000
NO_2	Annual Arithmetic Mean	2.5	25	1

NA = Not applicable, i.e., no standard exists for this pollutant or averaging period
Source: 40CFR50; 40CFR52.21, 40CFR51.165

3.2.4 Additional Impacts Analyses

The additional impact analysis consists of three elements:

1. Growth
2. Soils and Vegetation Impacts
3. Visibility Impairment

The growth analysis projects air pollutant emissions associated with industrial, commercial, and residential growth in direct support of the new source. Residential growth includes housing for employees entering the region while industrial and commercial growth includes new sources providing goods and services to the new employees and to the proposed source.

The analysis of impacts on soils and vegetation in the source's impact area compares the total air quality impacts to concentrations known to cause harmful effects to the resident species. The visibility impairment analysis addresses impacts that occur within the impact area of the proposed new source, beginning with an initial screening for possible impairment and, if warranted, a more in-depth analysis with computer modeling. The local visibility impairment analysis is distinct from the visibility impairment analysis required for PSD Class I areas, discussed below.

3.2.5 PSD Class I Area Analysis

In addition to the analysis of PSD Class I Increment compliance, the PSD Class I analysis must also address impacts to special attributes of a Class I area that deterioration of air quality may adversely affect. Such attributes are referred to as Air Quality Related Values and are specified by the Federal Land Manager (FLM) of the respective Class I area. These analyses generally include visibility impacts, such as plume blight or contribution to region haze, and impacts from acid deposition.

3.3 Good Engineering Practice Stack Height Analysis

EPA regulations require the degree of emission limitation required for control of any pollutant not to be affected by a stack that exceeds the Good Engineering Practice (GEP) height. GEP height is reflective of the height necessary to avoid having the exhaust caught in the downward flow of air currents created by structural and or ground effects, referred to as downwash. The portion of a stack, if any, that exceeds GEP height as defined by EPA cannot be used in atmospheric modeling of the source's impacts. Conversely, the dispersion modeling of emissions from stacks below GEP height must reflect the downwashing effects.

3.4 New Source Performance Standards

New Source Performance Standards (NSPS) apply to all sources within a given source category, regardless of geographic location or NAAQS attainment status. The standards define emission limitations that would be applicable to a particular source group. For PSD sources, BACT can be no less stringent than any applicable NSPS. The NSPS (contained in 40 CFR 60) applicable to the project will include:

- Subpart A – General Provisions
- Subpart Da – Electric Utility Steam Generating Units
- Subpart Dc – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- Subpart Y – Coal Preparation Plant
- Subpart OOO – Nonmetallic Mineral Processing Plant
- Subpart Kb – Volatile Organic Storage Vessels

3.4.1 Subpart A - General Provisions

Certain provisions of 40 CFR Part 60 Subpart A apply to the owner or operator of any stationary source subject to a NSPS. Since the two supercritical pulverized coal-fired boilers (Subpart Da), the three auxiliary boilers (Subpart Dc) and coal handling/processing (Subpart Y) will be subject to a NSPS, the Desert Rock Energy Facility will be required to comply with all applicable provisions of Subpart A. Subpart A provisions which impose requirements on the Desert Rock Energy Facility are identified in Table 3-6.

Table 3-6
Summary of Regulatory Requirements of NSPS Subpart A – General Provisions

40 CFR Subpart A Section	Requirement	Compliance Action
60.7	Initial notification and recordkeeping	Steag will submit all NSPS related notifications to EPA Region IX for the proposed project in a timely manner.
60.8	Performance Tests	Steag will conduct all required performance tests using designated reference test methods.
60.11	Compliance with standards and maintenance requirements	Steag will operate and maintain the units using good air pollution control practices
60.13	Monitoring requirements	Required pollutant monitoring pursuant to NSPS will utilize methods outlined in 60.13.
60.19	General notification and reporting requirements	All NSPS reports and notification will follow the format and schedule set forth in 60.19.

3.4.2 Subpart Da - Standards Of Performance For Electric Utility Steam Generating Units

Subpart Da regulations apply to steam generating units for which construction, modification, or reconstruction commenced after September 18, 1978 and that have a heat input capacity of greater than 250 million Btu/hour. Since the coal fired boilers will have a heat input greater than 250 MMBtu/hr and meet the "steam generating unit" definition, they will be subject to Subpart Da.

Subpart Da specifies emissions limitations, monitoring, reporting and record keeping requirements for PM, NO_x, SO_2 and opacity. A summary of the emission limitations and monitoring device requirements for each regulated pollutant is provided in Table 3-7.

The Desert Rock Energy Facility will be required to install a continuous emissions monitor (CEM) for opacity, SO_2 and NO_x pursuant to 40 CFR §60.47a(a), (b) and (c) and a CEM for O_2 or CO_2 pursuant to 40 CFR §60.47a(d). An initial performance test is required to demonstrate compliance with particulate matter, opacity, NO_x and SO_2 emission standards in accordance with the test methods specified in §60.48a. Compliance with the NO_x and SO_2 standards will be determined based on a 30-day rolling average of NO_x and SO_2 emissions as measured by the CEMS.

Table 3-7
Summary of Regulatory Requirements of NSPS Subpart Da

Pollutant	Emission Limit[1]	Monitoring
Particulate Matter	0.03 lb/MMBtu and 99% reduction	None
Opacity	20% (6-minute average), except one 6-minute period per hour of no more than 27%.	Continuous Emissions Monitor (CEM) for opacity or alternative monitoring technique, and either O_2 OR CO_2. Monitor must meet the requirements of §60.48a unless the CEM is installed to meet the requirements of 40 CFR §75.
Sulfur Dioxide	1.2 lb/MMBtu and 90% reduction, except 70% reduction when emissions are less than 0.60 lb/MMBtu; compliance is determined over a 30-day rolling average.	CEM for SO_2, and either O_2 Or CO_2. Monitor must meet the requirements of §60.48a unless the CEM is installed to meet the requirements of 40 CFR §75.
Nitrogen Oxides	1.6 lb/Mw-hr (gross); compliance is determined over a 30-day rolling average.	CEM for NOx, and either O_2 OR CO_2. Monitor must meet the requirements of §60.48a unless the CEM is installed to meet the requirements of 40 CFR §75.
1. Emission limits do not apply during periods of startup, shutdown or malfunction		

Record keeping and reporting requirements are also imposed by this subpart (i.e., 40 CFR §60.49a). The results of the initial performance tests as well as the performance tests of the CEM must be submitted to EPA Region IX. Specific record keeping requirements are identified which need to be performed on a daily basis and over a 30-day operating period. The CEM system data is submitted to EPA Region IX in an acceptable electronic format on a quarterly basis. In addition, this subpart specifies separate record keeping and reporting requirements that must be followed during any emergency or malfunction of combustion and/or emission control systems or monitoring equipment, especially those events that result in excess emissions.

Information that must be recorded in a permanent log includes the following:

- Identification of the operating days when the 30-day rolling average SO_2 and NOx emission rates are in excess of the applicable SO2 and NOx limits, along with the reason(s) for the excess emissions.
- List of days the PC boiler operated for which no pollutant data have been obtained.

- Identification of the times when emissions data have been excluded from the calculation of average emission rates and the reason(s) why.
- Identification of the "F" Factor, method of determination, and type of fuel combusted.

  The "F" Factor will be determined during initial performance testing. If the "F" Factor is recalculated during subsequent testing, the change will be noted in the quarterly reports submitted to EPA Region IX.
- Identification of the times when the pollutant concentration exceeds full span on the CEM.
- Description of any modifications made to the CEMS equipment.
- Results of the daily CEM drift tests and quarterly accuracy assessment. Daily drift tests will be performed and recorded in the Data Acquisition Handling System (DAHS), but not submitted to EPA Region IX. Failed drift tests will be noted in the quarterly reports submitted to EPA Region IX.

Excess emission reports, including all of the record keeping data noted above, must be submitted quarterly. Otherwise, semi-annual reports will need to be prepared and submitted to supplement the quarterly excess emission report. All records must be maintained for at least two years following the date of the record.

3.4.3 Subpart Dc - Standards Of Performance For Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc regulations apply to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). This subpart would therefore apply to the three auxiliary boilers, which are rated at a heat input capacity of 86.4 MMBtu/hr.

For SO_2 emissions standards, Subpart Dc 60.42c(d) applies to this equipment. It states, "On and after the date on which the initial performance test is completed or required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur." The SO_2 emission limits and fuel oil sulfur limits under this section apply at all times, including periods of startup, shutdown, and malfunction.

For particulate emissions standards, Subpart Dc 60.43c(c) applies to this equipment. It states, "On and after the date on which the initial performance test is completed or required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than

27 percent opacity." The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

Subpart Dc requires notification of the date of construction or reconstruction, anticipated startup, and actual startup, of the facility. The design and annual capacity factors must be included in this notification.

3.4.4 Subpart Y – Coal Preparation Plant

Although the coal supply for the Desert Rock Energy Facility will be from the adjacent Navajo Nation coal reserves leased to the BHP Billiton mine, the power plant will have a coal handling system. The coal handling system is subject to the provisions of Subpart Y for Coal Preparation Plants, which have been promulgated at 40 CFR §60.250 *et seq*. These provisions apply to affected facilities in which coal preparation plants process more than 181 Mg (200 tons) per day of coal. The affected facilities at the power plant include the coal processing and conveying equipment, coal storage systems and coal transfer and loading systems.

Subpart Y limits the opacity to 20% from any coal processing and conveying equipment, coal storage system or coal transfer and loading system processing coal. The Desert Rock coal handling system is designed with dust suppression, containment, collection and enclosures that will limit the opacity to less than 20%.

Subpart Y requires an initial performance test using EPA-approved test methods to demonstrate compliance with the aforementioned emission limits. Opacity is verified by Reference Method 9 and procedures described in 40 CFR §60.11.

3.4.5 Subpart OOO – Nonmetallic Mineral Processing Plant

Subpart OOO applies to certain activities at nonmetallic mineral processing plants. Limestone, which will be used for the emissions control systems, is classified as a nonmetallic mineral. The requirements of Subpart OOO will apply to limestone material handling activities at the Desert Rock Energy Facility such as transfer, silos/storage bins, and loading.

The requirements of Subpart OOO include an emission limit of 0.022 gr/dscf and 7% opacity on stack emissions from transfer points, 10% opacity from fugitive emissions from belt conveyors, 15% opacity from fugitive emissions from crushers, and 7% opacity from baghouse emissions from storage bins related to limestone handling systems. Compliance will be determined using EPA Reference Method 5 for stack emissions and Reference Method 9 for opacity determinations. Reporting will follow the requirements contained in §60.675.

3.4.6 Subpart Kb – Volatile Organic Liquid Storage Vessels

Distillate oil fuel for the auxiliary boiler and emergency engines will be stored on-site in a 1.1 million gallon tank. A new tank of this size will be subject to Subpart Kb. Due to the low vapor pressure of distillate oil, this tank will be exempt from all provisions of Subpart Kb as specified in §60.110b(c) except for the design capacity recordkeeping requirements at 40 CFR §60.116b(a).

3.5 National Emissions Standards for Hazardous Air Pollutants

National Emissions Standards for Hazardous Air Pollutants (NESHAP) are reflected in a requirement for Maximum Achievable Control Technology (MACT) standards, determined by EPA through an analysis of the best controlled sources in a category and the cost of more stringent available controls. A new source emitting more than 10 tons per year of a single Hazardous Air Pollutant (HAP) or 25 tons per year of a combination of HAPs is defined as a major source and must secure MACT approval prior to construction. If a MACT standard has not yet been promulgated for the source category, the applicant must secure case-by-case MACT approval (Subpart B).

A MACT standard for the oil- and coal-fired electric utility steam generating unit source category has not yet been promulgated, but a regulation (Subpart UUUUU) was proposed in January 2004, with a supplementary notice in March 2004. MACT standards for industrial boilers (Subpart DDDDD) and internal combustion engines (Subpart ZZZZ) have also been proposed, and final rules have been signed but not yet been published in the Federal Register. Since the project is expected to be a major source of HAP, a case-by-case MACT approval will be required if these proposed regulations are not finalized prior to PSD permit issuance. Even if not finalized during permit application processing for the Desert Rock Energy Facility, the proposed MACT standards will be used as needed for a case by case determination.

3.6 Title V – Major Source Operating Permit

Currently, the Navajo Nation has not been delegated authority for the Title V program. Until such authority is granted, a Title V permit under 40 CFR Part 71, administered by EPA, would be needed.

The Desert Rock Energy Facility will be required to submit a Title V operating permit application to EPA (or the Navajo Nation if they received Title V delegation prior to the facility's one-year operation anniversary date) no later than 12 months after the commencement of operation. The application and permit will essentially incorporate the requirement for operation encompassed by the PSD permit.

3.7 Compliance Assurance Monitoring

On October 27, 1997, EPA promulgated the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, which addresses monitoring for certain emission units at major sources, thereby assuring that facility owners and operators conduct effective monitoring of their air pollution control equipment. In order to be subject to CAM, the following criteria must be met:

- The unit is subject to an emissions limitation or standard for the pollutant of concern;
- An "active" control device is used to achieve compliance with the emission limit; and
- The emission unit's pre-control potential-to-emit is greater than the applicable major source threshold.

The CAM rule does not apply to emissions units/pollutants that are subject to Sections 111 (NSPS) or 112 (NESHAP) of the CAA issued after November 15, 1990; the Acid Rain program or emissions trading programs. Most emissions units/pollutants at the proposed project would be covered by other monitoring requirements. Monitoring plans for any emissions units/pollutants subject to CAM would be required to be developed with the submittal of the facility's Title V permit application.

3.8 Acid Rain Provisions

The proposed coal-fired boilers for the Desert Rock Energy Facility are subject to the Acid Rain Program (ARP) pursuant to Title IV of the CAA Amendments of 1990. This will require:

- An Acid Rain Permit
- Continuous Emissions Monitoring System conforming to the ARP requirements.
- Allowances equivalent to annual SO_2 emissions; and
- Emission limits of 40 CFR 76, to which BACT limits will conform or exceed.

The Acid Rain permit application must include the date that the unit will commence commercial operation and the deadline for monitoring certification (90 days after commencement of commercial operation). A Title IV Acid Rain monitoring plan will be submitted as required under 40 CFR 72. The plan will include the installation, proper operation and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for NO_X, SO_2, CO_2, and opacity. Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan also will cite the specific form of records that will be maintained, their availability for inspection, and the length of time that they will be archived. The plan will cite that the Acid Rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and the specific mechanism that will be used to keep current on rule applicability.

3.9 Risk Management Program

The project will utilize anhydrous ammonia in the selective catalytic reduction system, in addition to low-NOx burners, to control NOx emissions from the boilers. The storage amount of anhydrous ammonia will require a Risk management Plan in accordance with EPA rules. Three elements comprise the RMP:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

An approved RMP must be in place prior to exceeding the threshold storage amount of anhydrous ammonia (10,000 lbs) at the Desert Rock Energy Facility.

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4.0 CONTROL TECHNOLOGY EVALUATION

4.1 Control Technology Overview

The Project is subject to Best Available Control Technology (BACT) for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter smaller than 10 micrometer diameter (PM_{10}), Volatile Organic Compounds (VOCs), lead (Pb), hydrogen fluoride (HF), and sulfuric acid mist (H_2SO_4). Mercury (Hg) and hydrogen chloride (HCl) have been targeted for future regulation under the Maximum Available Control Technology (MACT) standards for coal-fired power plants. This document presents a “Top Down” BACT analysis, which begins with identification of the most stringent level of control achieved on similar units. This level of control is referred to as the Lowest Achievable Emission Rate (LAER). BACT is presumed to be equivalent to LAER unless case-specific technical feasibility, economic or environmental impacts would preclude it’s practical application to the proposed project. If such factors are identified, the next best level of control is similarly evaluated, and this process continues until the BACT level is determined on a case-by-case basis for the particular emission units being evaluated for control.

While new MACT regulations for utility power plants, industrial boilers, and engines have been proposed by EPA, they are not yet final. It is clear that any newly proposed coal fired power plant will have to be designed for aggressive mercury control to meet future requirements. Furthermore, many of the same control technologies that represent BACT candidates have also been shown capable of mercury reduction, and therefore it is useful to consider the holistic application of state-of-the-art emissions control during facility design. As of this writing, a case-by-case MACT analysis is required for mercury, and has been presented herein as part of the overall control technology review of the proposed facility.

4.1.1 Lowest Achievable Emission Rate

While the proposed project is not subject to the requirement to install LAER for any pollutant, in a Top Down control technology analysis LAER is used as the starting point since it establishes the lowest emission level that has been demonstrated in practice for a similar pulverized coal-fired power plant. . LAER, as defined in the "New Source Review Workshop Manual" (EPA, October 1990), is derived from either of the following definitions:

> *"The most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or the most stringent emission limitation achieved in practice by such class or category of source."*

The LAER standard is more stringent than BACT, since it considers only technological applicability of the best level of control that has been achieved in practice on another similar Unit, without consideration of potential adverse economic, environmental, or energy impacts. It does, however, represent a useful starting point in the evaluation of potentially achievable levels of control. To determine the applicable emission limitations that would be representative of LAER, several sources were consulted including EPA's RACT/BACT/LAER Clearinghouse, representatives of EPA, and PSD permits issued for other recent coal-fired power plants not yet listed in the EPA Clearinghouse.

4.1.2 Top-Down BACT

BACT requirements are intended to ensure that a proposed facility will incorporate control systems that reflect the latest demonstrated practical techniques for a particular type of emission unit and do not result in the exceedance of a NAAQS, PSD increment, or other standard imposed at the state level. The top-down BACT evaluation requires documentation and ranking of performance levels achievable for each technically feasible pollutant control technology applicable to the Desert Rock Energy Facility.

The top-down approach to the BACT review process involves determining the most stringent control technique available (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the particular source under evaluation, then the next most stringent level of control is determined and similarly evaluated. The process continues until a control technology and associated emission level is determined which cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in the EPA draft document "New Source Review Workshop Manual. The five steps involved in a top-down BACT evaluation are:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Eliminate technically infeasible technology options;
- Rank remaining control technologies by control effectiveness;
- Evaluate most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and
- Select BACT, which will be the most effective practical option not rejected based on energy, environmental, and economic impacts.

The "top-down" approach was used in this analysis to evaluate available pollution controls for the proposed Desert Rock Energy Facility.

4.1.3 Previous BACT/LAER Determinations for Pulverized Coal-fired Boilers

EPA's RACT/BACT/LAER Clearinghouse (RBLC) is a listing of RACT, BACT, and LAER determinations by governmental agencies for many types of air emission sources. ENSR consulted this database as the first step in developing a list of the most recent BACT/LAER decisions for applicable source types including pulverized coal facilities. The results of the RBLC search and information from more recent permits are summarized on a pollutant specific basis in the following sections to identify and rank alternative technologies and achievable levels of control.

4.2 BACT for Nitrogen Oxides (NO_x)

4.2.1 Pulverized Coal-fired Boilers

4.2.1.1 Formation

NO_x is formed during the combustion of fossil fuels including coal and is generally classified as either thermal NO_x or fuel NO_x. Thermal NO_x is formed when elemental nitrogen reacts with oxygen in the combustion air within the high temperature environment of the furnace. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel NO_x is generated when nitrogen contained in the coal itself is oxidized. The rate of formation of fuel NO_x is primarily a function of fuel bound nitrogen content of the coal but is also affected by fuel air mixing.

NO_x emissions can be reduced using either combustion controls (i.e., staged combustion techniques such as Low-NO_x burners (LNB), flue gas recirculation (FGR), overfire air (OFA), natural gas reburn, or flue gas treatment including selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR). SCONO$_x$ is a proprietary catalytic control technology that has been applied to several small gas turbines, however it has never been applied to a coal fired application and therefore has not been considered further in this analysis. Most facilities being permitted today incorporate both combustion controls and add-on control to achieve NO_x control.

4.2.1.2 Ranking of Available Control Techniques

A review of EPA's RBLC (see Attachment 2) and recent permit reviews indicates general levels of NO_x control that may be achieved with various combinations of control technology. Emission levels and control technologies for pulverized coal combustion have been identified and ranked as shown in Table 4-1.

4.2.1.3 Recent Permit Levels

The four most recent PSD permits identified for new pulverized coal-fired units are Sand Sage Power, LLC in Kansas issued 10/8/02, Thoroughbred Generating Co. LLC in Kentucky, issued 10/11/02, Roundup Power in Montana issued 07/21/03 and Longview Power, LLC in West Virginia draft issued 12/4/03. Each of these projects were subject to top down BACT, and the emission limits contained in those BACT approvals are representative of the current state-of-the-art for new pulverized coal power plants. It should be noted that many of the recent power plant permits, especially in the West, propose to burn Powder River Basin (PRB) coal from Wyoming. The Desert Rock Energy Facility will be a mine-mouth plant burning subbituminous coal mined on the Navajo Reservation in New Mexico. In fact, the proposed Desert Rock project is not located near rail service, and it will be impracticable to use PRB coal. To the extent that other projects will achieve BACT based on use of a different coal type (i.e. Powder River Basin coal vs. New Mexico subbituminous), permitted emission levels may need to be adjusted to the equivalent level that can be achieved with the particular coal type that is available to the Desert Rock Energy Facility.

Table 4-1
Ranking of NO_x Control Technologies for Pulverized Coal Boilers

Pulverized Coal Control Technologies	**Typical Control Efficiency Range (% Removal)**	**Typical Emission Level[1] (lb/MMBtu)**	**Technically Feasible for Pulverized Coal Boilers**
SCR and Low-NO_x Burners	80-90	0.07-0.15[2] lb/MMBtu	Yes
SNCR	40-60	0.2-0.3 lb/MMBtu	Yes
Staged Combustion Techniques Including Low-NO_x Burners	30-50	0.15-0.5[3] lb/MMBtu	Yes
SCONOx™	N/A	N/A	No
Gas Reburn	40-60	0.15-0.3 lb/MMBtu	Requires Natural Gas On Site

1. Emission levels represent target steady state values at base load, long-term averages. All known projects also incorporate staged combustion techniques such as Low-NO_x Burners.
2. An exception to this range is the W. A. Parish facility in Texas which is being designed to limit NO_x emissions to 0.03 lb/MMBtu with Alstom Low-NO_x burners and SCR. However this facility will use PRB coal. Such lower NOx levels may be achievable with PRB coal in tangentially or corner fired boilers due to the higher reactivity of the PRB coal, lower fuel nitrogen content and greater percentage of fuel nitrogen in the volatile fraction. However, the proposed project is a New Mexico mine mouth plant and cannot utilize PRB coal.
3. The lower end of this range is only achievable using PRB coal in tangentially or corner fired boilers.

N/A – Not available (no known installations of this technology on utility scale coal-fired boilers)

The Thoroughbred Project will employ SCR to achieve a NO_x emission limit of 0.08 lb/MMBtu on eastern bituminous coal. This value has been proposed and demonstrated in practice on similar units burning eastern coal. The permit for Sand Sage, which will fire Powder River Basin coal was permitted with a goal of achieving 0.08 lb/MMBtu after three years of operation, with an interim limit of 0.12 lb/MMBtu. The permit contains a provision to adjust the 0.08 lb/MMBtu upward if it is shown that despite good faith efforts it can not be continuously achieved in practice. The Roundup Power permit (western bituminous) requires low-NO_x burner, overfire air and SCR to limit NO_x emissions to 0.07 lb/MMBtu as a 24-hour average. The Longview permit requires low-NO_x burners and SCR to limit NO_x emissions to 0.08 lb/MMBtu as a 24-hour average.

Based on these four recent BACT determinations, ENSR concludes that SCR in the range of 0.07 – 0.08 lb. NO_x/MMBtu is representative of state-of-the-art emission control for new pulverized coal units.

The Reliant Energy/Texas Genco W. A. Parish Unit 8 retrofit project in the Houston Texas area has a design goal of 0.03 lb/MMBtu. This project is in the Houston–Galvenston ozone nonattainment area where large system wide NO_x reductions are required to make progress toward attainment. Reliant

Energy/Texas Genco plans to over-control Unit 8 so that they do not have to limit NO_x emissions from other units in their system to low levels. The W. A. Parish Station project is designed to limit NO_x emissions from the boiler by using Low-NO_x burners to reduce emissions to 0.15 lb NOx/MMBtu. However, this level of NO_x emissions, using Low-NO_x burners, has only been demonstrated on tangentially or corner fired boilers using PRB coal and not on New Mexico coal. SCR at 80% control efficiency will further reduce NO_x emissions to 0.03 lb/MMBtu. The design emission levels are long term average targets rather than continuous binding 24-hour average PSD emission limits. If 0.03 lb/MMBtu cannot be achieved, Texas Genco may be able to meet their overall goal through reductions on other units. This unit has been installed but has only operated for a few days as of May 3, 2004, and hence cannot be considered to have been demonstrated in practice over long-term, continuous operation. For these reasons, the W. A. Parish Unit 8 project does not represent a technically feasible level of control for the Desert Rock Energy Facility.

Alternative control technologies with potential for application to the Desert Rock Energy Facility (using Navajo Reservation coal) are reviewed below.

4.2.1.4 NO_x Control Technology Discussion

Selective Catalytic Reduction

SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system. The SCR reactor with necessary inlet and outlet duct work will be located downstream of the economizer and upstream of the air heater and the particulate control system.

From the economizer outlet, the flue gas will first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas will then flow through the catalyst bed and exit to the air heater.

The SCR system for a pulverized coal boiler typically utilizes a fixed bed catalyst in a vertical down-flow multi-stage reactor. The reactor will include a seal system to prevent gas from bypassing the catalyst bed. Access openings for catalyst loading/removal and periodic internal inspection will be provided. The reactor will contain multiple stages of catalyst with room for loading a future stage. For each stage, a soot blowing system will be provided. Each stage will be equipped with a platform with monorails and hoists to accommodate catalyst loading and unloading.

Reduction catalysts are divided into two groups: base metal (lower temperature, primarily vanadium, platinum or titanium) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown to also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of ammonia to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Optimum operating temperature for a vanadium-titanium catalyst system has been shown to be in the range of 550° to 800°F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operating at temperatures above this range. Consequently, operating above the maximum temperature for the catalyst system again results in the oxidation of ammonia to either nitrogen oxides (increasing NO_x emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. At typical SCR operating temperatures, SO_3 and sulfuric acid react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled and can lead to increased uncontrolled emissions of PM_{10} entering the particulate collector. Fouling may eventually lead to decreased NO_x reduction performance, increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a limited lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 ppmvd of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which conversely results in ammonia slip. Thus an emissions trade-off between NO_x and ammonia may occur in high NO_x reduction applications.

The potential environmental impacts associated with the use of SCR are summarized below:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip).
- Ammonium salts would increase loading to the particulate collection stage as PM_{10} (and $PM_{2.5}$).
- Safety issues and Risk Management Planning may be required relative to the transportation, handling, and storage of ammonia (aqueous or anhydrous).

The application of SCR to coal-fired boilers was first developed in Germany, in response to German air regulations. SCR units had operated in Germany for ten years before they were first applied to coal-fired boilers in the U. S. and German utilities have now accumulated over twenty years of operating experience with this technology. Steag AG is one of these German utilities, and together with Encotec (it's German engineering subsidiary), has far more design and operational experience in the advanced application of SCR technology to coal-firing than it's U. S. counterparts. This special knowledge and expertise is the basis for the design and emission reduction capability determination for the proposed Desert Rock Energy Facility.

Selective Non-Catalytic Reduction

SNCR has been applied to a number of different types of combustion sources, including petroleum heaters, utility and industrial boilers fired with natural gas and oil, as well as PC boilers and to coal-fired Circulating Fluidized Bed (CFB) boilers.

The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and either injected NH_3 or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_x reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process.

Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 - 1,900°F; for the urea injection process the nominal temperature range is 1,600 - 2,100°F. Also critical to effective application of these processes are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia (or one-half mole of urea) will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess reagent and essentially achieving low NO_x emissions at the expense of emissions of unreacted reagent, referred to as ammonia "slip." These emissions represent an adverse environmental impact and can lead to formation of ammonium salts and may contribute to regional haze as a precursor to $PM_{2.5}$. Thus, for a given boiler configuration, there is a limit on the degree of NO_x reduction which can be achieved with SNCR while maintaining acceptable levels of ammonia slip.

A number of CFB boilers have been equipped with SNCR for NO_x control as BACT according to the listings in the RACT/BACT/LAER Clearinghouse. The CFB design is described as the ideal application for SNCR in the available open literature. CFB boilers are constant temperature, variable heat transfer devices. The bed temperature and downstream flue gas temperature can be set by the operator to within a few degrees. The typical temperature of CFB flue gas leaving the bed and entering the hot cyclone is at the ideal temperature for SNCR. Additionally, the reduction reagent is injected at the inlet to the hot cyclone, where all of the flue gas is swirled at 50-75 ft/second, and forced to change direction many times. This cyclonic action homogenizes the reagent flue gas NO_x concentration, thus maximizing mixing. Pulverized coal-fired units have a much more limited furnace temperature window and poor lateral mixing, conditions which render SNCR less effective in these applications. SNCR has been applied to PC boilers more often to achieve 30 – 50% reductions in response to Reasonably Available Control Technology (RACT) since the technology can be retrofit more readily than add-on control. Due to mixing limitations and a brief temperature window in which to react, SNCR is fundamentally less effective at controlling NO_x from PC's compared with CFB's.

Staged Combustion

A number of techniques have been employed to reduce the formation of NO_x by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO_x. Staged combustion techniques include Low-NO_x burners, flue gas recirculation, overfire air, burners out of service, and combinations of these. A collateral impact of staged combustion is an increase in emissions of products of incomplete combustion including CO, VOC and carbon in ash (referred to as Loss on Ignition, or LOI).

SCONOx

SCONOx is a NO_x adsorption/desorption technology that has been applied to combustion turbines that fire natural gas. This technology is extremely sensitive to the presence of sulfur in flue gas and could not be applied to coal-fired boilers. SCONOx is therefore determined to be not technically feasible for application to the proposed PC boilers and is not evaluated further in this analysis.

Gas Reburn

Natural gas reburn is a control technique that has shown promise as a potential retrofit to existing boilers, and may be capable of reducing emissions of NO_x to 0.15 lb/MMBtu simply by starving the coal burners for excess oxygen and completing combustion with 12-15% gas in the upper furnace.

Application of this technology assumes that natural gas in substantial quantity is already available on site – otherwise it is technically infeasible. In any event, the level of NO_x control that may be achieved is less than for the other add-on control technologies and therefore it is not considered further in this analysis.

4.2.1.5 Summary of Pulverized Coal-fired Boiler BACT for NO_x

Based on a review of available control technologies for emissions of NO_x from a pulverized coal-fired boiler, as well as 20+ years of Steag field experience and expertise in the application of SCR to coal-fired boilers, we conclude that the lowest NO_x emission rate that have been demonstrated in practice and can be achieved for the particular coal available to Desert Rock Energy Facility is 0.06 lb/MMBtu as a 24-hour average. This emission rate represents the best emissions control technology available for the proposed PC boilers, and therefore represent Lowest Achievable Emission Rate (LAER) as well as a top-down BACT that is beyond previously established BACT emission limits. No adverse cost, energy, or environmental impacts have been identified that would prevent the proposed project from continuously achieving 0.06 lb/MMBtu as a 24-hour average.

BACT for NO_x for the Steag Desert Rock Energy Facility is concluded to be emission limits of 0.06 lb/MMBtu as a 24-hour average using low-NO_x burners and selective catalytic reduction.

4.2.2 Auxiliary Boilers

The Desert Rock Energy Facility includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. These boilers will be subject to NSPS 40 CFR 60 Subpart Dc. Total annual fuel use in the three boilers will be limited to 142,560 MMBtu/year, which is equivalent to an average of only 550 hours of operation per year per boiler at full load.

Based on a review of recent permits for similar boilers and EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2), ENSR has concluded that BACT for NO_x for these boilers is 0.10 lb/MMBtu using Low-NO_x Burners. Only one permit, issued in 1997, requires the use of SCR, however that unit is allowed to operate at full load, year round, and not on a limited duty as planned here. We note that there are a couple of very small boilers listed in the Clearinghouse with NO_x emission rates of 0.038 lb/MMBtu, however we believe these listings to be in error (and note that they also do not reflect the same category of source). However, all of the 20 permits issued in the last 5 ½ years, for distillate oil-fired small industrial boilers have NO_x emission rates of at least 0.10 lb/MMBtu.

NO_x emissions from the auxiliary boilers will be controlled by limiting annual fuel use to a total of 142,560 MMBtu/year, limiting operation to low sulfur distillate oil, and using Low-NO_x burners to 0.1 lb/MMBtu, which represents BACT for these emission sources.

4.2.3 Emergency Diesel Engines

The Desert Rock Energy Facility includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). These emergency diesel engines will not operate for more than 100 hours/year each. NO_x emissions during operation will be controlled by only burning low sulfur distillate oil and ignition timing retard with turbocharging and aftercooling. Based on review of recent permits for similar emergency diesel engines and EPA's RACT/BACT/LAER Clearinghouse, the top level of control or lowest NO_x emission rate approximately 6.5 g/hp-hr. This level of control represents BACT for the emergency diesel engines.

4.3 BACT for Sulfur Dioxide

4.3.1 Pulverized Coal-fired Boilers

4.3.1.1 Formation

Emissions of sulfur dioxide are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. Approximately 98% of sulfur in solid fuels is emitted upon combustion as gaseous sulfur oxides. Uncontrolled emissions of SO_2 are thus affected by fuel sulfur content alone, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers in the U.S. limit emissions of SO_2 through the use of low sulfur western coals, including PRB coal. Compared with a high sulfur eastern bituminous coal that may contain as much as 4% sulfur, burning western coal can reduce SO_2 emissions by approximately 70% to 90%. The selection of coal type and sulfur content is therefore an important aspect of the determination of BACT and needs to be considered in conjunction with add-on control alternatives when performing the top-down analysis.

4.3.1.2 Ranking of Available Add-On Control Techniques

Generally, there are two types of add-on control applicable to a coal-fired boiler: in-situ combustion control (sorbent injection) and post-combustion control (flue gas desulfurization). In-situ control is used effectively in CFB boilers, and may be used in a PC boiler by using limestone injection into the furnace, however the level of control that is achievable is not comparable to post-combustion SO_2 control systems. Post-combustion controls applicable to PC boilers are a wet scrubbing system or spray dryer absorber (SDA) using reagents such as lime, limestone, sodium bicarbonate or magnesium oxide.

A comparative ranking of available SO_2 control technologies (see Table 4-2) must take into consideration multiple variables including coal sulfur content, % removal and the resulting emission rate (lb/MMBtu) in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts.

4.3.1.3 Recent Permit Limits

Most of the PSD permit limits listed in EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2) since 1995 are in the 0.12 lb SO_2 /MMBtu to 0.25 lb SO_2 /MMBtu range. Many of these have compliance averaging times in the 24-hour to 30-day range. In addition, there is one permit at 0.022 lb/MMBtu and six in the 0.086 to 0.12 lb/MMBtu range.

The lowest permit limit is 0.022 lb/MMBtu for AES-Puerto Rico, which is a smaller CFB Unit, and is a fundamentally different source type than the proposed Steag PC boilers. Additionally, the economics for AES-Puerto Rico are much different than those associated with the Desert Rock project and most other projects in the continental U.S. Puerto Rico is a captive market with electricity only available from the Puerto Rico Electric Power Authority, which is a utility. When AES-Puerto Rico was permitted, oil was the only fuel being used to generate electricity. AES-Puerto Rico was built to diversify the fuel supply and provide electricity at a price that would be competitive with oil fired boilers, not other coal fired boilers.

Table 4-2
Ranking of Sulfur Dioxide Technologies for Pulverized Coal Boilers

Control Technology	Typical Level of Control[1]	Typical Emission Level[1] (lb/MMBtu)	Technically Feasible for PC Boilers?
Wet Scrubber	90-98%	Depends on Coal sulfur content (lower with western coal)	Yes
Limestone Injection	25-35%	Depends on Coal sulfur content (lower with western coal)	Yes
Spray Dryer Absorber	70–92%	Depends on Coal sulfur content (lower with western coal)	Yes
Use of Low Sulfur Coal	30-90%	Western coals represent a 70-90% reduction compared with high sulfur eastern coals, lower reduction compared to other eastern coals	Yes
1. Emission levels represent steady state values. EPA AP-42 notes Limestone wet scrubbers at the high range of control efficiency are applicable to high sulfur fuels.			

The boilers at AES-Puerto Rico are circulating fluidized bed boilers with capacities of approximately 225 MW, which is near the practical size limit for CFB Units. CFB boilers are not available as 750 MW Units and are therefore not practical generating technology candidates for the Desert Rock Energy Facility. Hypothetically, it would take seven complete AES CFB boilers, with all of their supporting equipment and systems to produce the same output as the two proposed supercritical PC Units. This would not be an economically viable alternative for a 1,500 MW power plant due to prohibitive capital cost, and substantially increased operating and maintenance costs. These factors together would defeat the design goals of the Desert Rock Energy Facility – that is, the environmentally sensitive and economical production of power utilizing Navajo Nation fuel resources. For these reasons, the emission level set for AES-Puerto Rico is not applicable to the proposed 1,500 MW power plant. This viewpoint is confirmed by every Top-Down BACT decision (all issued with higher SO_2 emission rates) since the original AES-Puerto Rico permit in 1998.

The two most recent PSD permits issued are the Roundup Power Project in Montana (07/21/03) and the Longview Power Project in West Virginia (draft 12/04/03). Both of these projects have top-down BACT decision SO_2 permit limits of 0.12 lb/MMBtu as 24-hour averages. On a short-term basis, the Longview permit limit also has a 0.15 lb/MMBtu as a 3-hour average and the Roundup permit 0.15 lb/MMBtu as a 1-hour average.

4.3.1.4 SO_2 Control Technology Discussion

Wet Flue Gas Desulfurization

The most frequently utilized wet flue gas desulfurization (FGD) technology is the wet limestone spray tower system. Typically, flue gas enters at the bottom of the absorber tower, continues vertically through the limestone/water spray, passes through a mist eliminator to control the re-entrained slurry drops, and then exits the tower. Limestone (calcium carbonate) reacts with the sulfur dioxide to form calcium sulfite. The calcium sulfite may then be oxidized to form calcium sulfate, since it is easier to de-water than calcium sulfite. This can be achieved by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank.

To fully utilize the limestone, the slurry is re-circulated through the tower and a bleed stream is taken off for de-watering. The bleed stream can be de-watered using a variety of techniques, including thickeners, centrifuges and vacuum filters. The final slurry may contain 10% to 40% water by weight.

Wet scrubbers can also utilize limestone rather than lime. Some of the lime (calcium oxide) becomes calcium hydroxide in water. The slurry of calcium hydroxide and lime is fed to the spray tower. Since the cost of limestone is much less than lime, the limestone alternative is much more common. This is especially the case for medium to high sulfur coals.

Spray Dryer Absorber

The spray dryer absorber is located upstream of the particulate collection system, typically fabric filters. The flue gas passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the spray dryer absorber through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and reacts with the SO_2 in the flue gas to form insoluble calcium salts. The flue gas is cooled to approximately 18 to 30 °F above the adiabatic saturation of the flue gas. The calcium salts have a moisture content of approximately 2 to 3%, which falls to 1% before reaching the particulate control device. When a fabric filter is used as the particulate control device, it allows for further reaction of the lime with the sulfur (and other acid gases) in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of sulfuric acid mist, hydrogen chloride and mercury as compared to wet scrubbers.

Use of Low Sulfur Coal

Any discussion of the relative effectiveness of add on SO_2 control must also take into account the level of uncontrolled SO_2 to be handled, which is highly dependent on the sulfur content of the coal to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of SO_2 in the flue gas, and vice versa. This is reflected in a comparison of the resulting emission rate in units of lb of SO_2 per MMBtu of fuel burned (or lb of SO_2 per kW produced). For example, a proposed project with a BACT limit of 0.16 lb/MMBtu using an 80% removal control system is environmentally superior to another project with a BACT limit of 0.32 lb/MMBtu and 95% removal. For a project located in the Western U.S., BACT generally includes use of low sulfur western coal as a part of a strategy to limit SO_2 to BACT levels in combination with add-on control.

4.3.1.5 Summary of Pulverized Coal-fired Boiler BACT for SO_2

Steag is proposing to limit SO_2 emissions to 0.06 lb/MMBtu as a 24-hr average by burning low sulfur western coal and using a wet limestone flue gas desulfurization system. This proposed emission rate is lower than any other project listed in EPA's RACT/BACT/LAER Clearinghouse, except for AES-Puerto Rico, which was previously discussed. Steag's proposed emission limit of 0.06 lb/MMBtu as a 24-hour average is much lower than the two most recent permits which are the Roundup Power Project in Montana (07/21/03) and the Longview Power Project in West Virginia (draft 12/04/03). Both of these projects have SO_2 permit limits of 0.12 lb/MMBtu as 24-hour averages or 100% higher than the proposed Desert Rock Energy Facility. Therefore, Steag has made a conscious decision to achieve even lower SO_2 levels and this level of control is concluded to go beyond BACT for SO_2 from the proposed Desert Rock PC boilers.

4.3.2 Auxiliary Boilers

The Desert Rock Energy Facility also includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBtu/year, which is equivalent to an average of 550 hours/year per boiler at full load. SO_2 emissions will be controlled by only burning low sulfur distillate oil with a maximum sulfur content of 0.05%. No add-on SO_2 controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO_2 control option and is the top level of control. Therefore, Steag proposes to only burn low sulfur distillate oil (0.05% sulfur maximum) and to restrict total annual fuel consumption to 142,560 MMBtu/year as BACT for the auxiliary boilers.

4.3.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). These energency diesel engines will not be operated for more than 100 hours/year each. No add-on SO_2 controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO_2 control option and represents the top level of control. Therefore, Steag proposes to only burn low sulfur distillate oil (0.05% sulfur maximum) and to restrict operation to 100 hours per year each as BACT for the proposed emergency diesel engines.

4.4 BACT for Carbon Monoxide

4.4.1 Pulverized Coal-fired Boilers

4.4.1.1 Formation of CO Emissions

Carbon monoxide is formed as a result of incomplete combustion of a hydrocarbon fuel. Control of CO is accomplished by providing adequate fuel residence time, excess oxygen and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through combustion modification techniques such as Low-NO_x Burners can result in higher levels of CO formation. Thus, a compromise is established to achieve the lowest NO_x formation rate possible while keeping CO emission rates at acceptable levels.

4.4.1.2 Ranking of Available CO Control Technology Options

CO emissions from pulverized coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All pulverized coal-fired boilers identified utilize front-end methods such as good combustion control wherein CO formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for pulverized coal-fired boilers utilize combustion control techniques for CO (see Attachment 2). While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology is not applicable to coal-fired boilers. In addition to oxidizing CO, an oxidation catalyst would oxidize SO_2 to produce SO_3, which would exacerbate sulfuric acid mist emissions. The SO_2 oxidation rate would be in the range of 5% or more resulting in very high sulfuric acid mist emissions if an oxidation catalyst were to be attempted on a coal-fired boiler.

BACT for CO for the recently permitted Roundup Power Project in Montana was approved in July 2003 as 0.15 lb/MMBtu. In December 2003, a CO BACT emission limit of 0.11 lb/MMBtu was approved for the Longview Power Project in West Virginia. EPA's RACT/BACT/LAER Clearinghouse lists more than 30 permits in the 0.10 lb/MMBtu to 0.15 lb/MMBtu range and only one less than 0.10 lb/MMBtu.

A review of EPA's RACT/BACT/LAER Clearinghouse and ENSR's review of recent permit decisions, indicates levels of CO control which may be achieved for coal-fired boilers. Emission levels and control technologies have been identified and ranked in Table 4-3.

Table 4-3
Ranking of CO Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Combustion controls	0.05 to 0.15	Yes
Oxidation catalyst	Not determined	No
SCONOx	Not determined	No

4.4.1.3 CO Control Technology Discussion

Combustion Control

Combustion control refers to controlling emissions of CO through the design and operation of the boiler in a manner so as to limit CO formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also tend to reduce emissions of VOC as well as CO. However, this process must be optimized with the efforts to reduce NO_x emissions, which may increase when steps to lower CO are taken.

Catalytic Oxidation

Catalytic oxidation is the technology that has been used to obtain the most stringent control level for CO from natural gas-fired turbine combustion units. This technology has never been applied to a coal-fired unit. It is evaluated here to determine if it could be considered transferable technology for application to the proposed pulverized coal-fired boilers. In this alternative, a catalyst would be situated in the flue gas stream to lower the activation energy required to convert products of incomplete combustion (CO and VOC) in the presence of oxygen (O_2) to carbon dioxide and water. The catalyst permits combination of the reactant species at lower gas temperatures and residence times than would be required for uncatalyzed oxidation.

The catalyst would have to be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 °F and about 1,000 °F. Catalyst non-selectivity is a problem for sulfur containing fuels such as coal. Catalysts promote oxidation of SO_2 to SO_3 as well as CO to CO_2. The amount of SO_2 conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO_3 can be minimized to 5% of inlet SO_2. This level of conversion would result in a large collateral increase in H_2SO_4 emissions which aside from the increased ambient air impacts, could result in unacceptable amounts of corrosion to the fabric filter particulate collector, air preheater, ductwork and stack.

Oxidation catalysts are known to be extremely sensitive to potential masking, blinding or poisoning due to trace elements such as metals in flue gas. While natural gas contains essentially no trace metals, coal contains many of trace compounds within the inert fraction referred to as ash. These trace compounds are highly variable in concentration even from coal taken within the same mine or seam. There is no empirical evidence available to show that oxidation catalyst technology would actually work with coal-fired boilers, or if so what the life of the catalyst might be.

ENSR contacted an oxidation catalyst system vendor to determine the technical feasibility of installing this system on a coal-fired boiler. Due to the high particulate loading of the flue gas, variable trace element concentration in the flue gas and the SO_2 loading before air pollution control systems, the vendor stated that they could not provide a catalyst system for coal-fired applications. Consequently, oxidation catalyst systems are considered technically infeasible for application to the proposed coal-fired boilers.

SCONOx

SCONOx is a technology that has been widely discussed for application to many types of sources, however to date the only two known applications are on small gas turbine cogeneration systems. Like oxidation catalyst, this technology has never been applied or even tested for application to coal-fired boilers. In fact, SCONOx actually utilizes the same CO reduction technology as oxidation catalyst discussed previously. The SCONOx bed incorporates a coating of the same catalyst material, primarily to oxidize NO to NO_2 but with the side benefit of also reducing emissions of CO. SCONOx therefore has all the limitations cited above for oxidation catalyst, but is even further from consideration as transferable technology.

4.4.1.4 Summary of Pulverized Coal-fired Boiler BACT for CO

The only practical or demonstrated in practice measures to control CO from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of CO while also minimizing NO_x, therefore represents the BACT control technology for the proposed boilers. BACT for CO from the proposed Desert Rock PC boilers is therefore concluded to be 0.10 lb/MMBtu. This level is consistent with or lower than recent permits for new coal fired boilers and lower than the most recent top-down BACT decisions for the Roundup and Longview projects which were permitted in the 0.11 lb/MMBtu to 0.15 lb/MMBtu range.

4.4.2 Auxiliary Boilers

The Desert Rock Energy Facility includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBtu/year, which is equivalent to an average of 550 hours/year per boiler at full load. A BACT limit for CO emissions of 0.036 lb/MMBtu and the annual total fuel restriction of 142,560 MMBtu/year are proposed for these boilers, which reflect the lowest emission limits listed in EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2).

4.4.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. A BACT emission limit for these diesel engines of 0.5 g/hp-hr and a limitation of 100 hours of operation per year (each) represents BACT for the proposed emergency diesel engines.

4.5 BACT for VOC

4.5.1 Pulverized Coal-fired Boilers

4.5.1.1 Formation of VOC Emissions

VOCs are also emitted from coal-fired boilers as a result of incomplete combustion of the fuel. Control of incomplete combustion is accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

4.5.1.2 Ranking of Available VOC Control Technology Options

VOC emissions from coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All coal-fired boilers identified utilize front-end methods such as combustion control wherein VOC formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2) for coal-fired boilers utilize combustion control techniques for VOC. While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology is not applicable to coal-fired boilers as previously discussed.

4.5.1.3 Recent Permit Limits

BACT for VOC for the recently permitted Roundup Power Project in Montana was approved in July 2003 as 0.003 lb/MMBtu. In December 2003, a BACT emission limit of 0.004 lb/MMBtu was approved for the Longview Power Project in West Virginia. EPA's RACT/BACT/LAER Clearinghouse lists only five BACT decisions below 0.004 lb/MMBtu, twenty in the 0.005 lb/MMBtu to 0.01 lb/MMBtu range and several higher permit limits.

A review of EPA's RACT/BACT/LAER Clearinghouse, and ENSR's review of recent permit decisions, indicates levels of VOC control which may be achieved for pulverized coal-fired boilers. Emission levels and control technologies have been identified and ranked in Table 4-4.

Table 4-4
Ranking of VOC Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Combustion control	0.002 to 0.01 (LAER)	Yes
Oxidation catalyst	Not determined	No
SCONOx	Not determined	No

4.5.1.4 VOC Control Technology Discussion

Combustion Control

Combustion control refers to controlling emissions of VOC through the design and operation of the boiler in a manner so as to limit VOC formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also have the by-product of reducing the emissions of CO. Pulverized coal-fired boilers are designed specifically for efficient fuel combustion with thorough mixing and residence time at temperature, plus staged combustion. This level of combustion control represents BACT for the proposed boilers.

Add-On Emission Controls

Catalytic oxidation and SCONOx are not applicable to coal-fired boilers as previously discussed in Section 4.4.1.3.

4.5.1.5 Summary of Pulverized Coal-fired Boiler BACT for VOC

The only practical or demonstrated in practice measures to control VOC emissions from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of VOC while also minimizing NO_x, therefore represents BACT for the proposed boilers. Steag is proposing a VOC BACT limit of 0.003 lb/MMBtu, which is lower than the lowest emission rate in recent PC boiler permits.

4.5.2 Auxiliary Boilers

The project includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBtu/year, which is equivalent to an average of 550 hours/year per boiler at full load. BACT for VOC emissions is concluded to be an emission limit of 0.0024 lb/MMBtu and a total fuel restriction of 142,560 MMBtu/year for these boilers based on EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2).

4.5.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. A BACT emission limit for these diesel engines of 0.3 g/hp-hr and an operating restriction of 100 hours per year (each) represents BACT for VOC from these units based on EPA emission factors in AP-42.

4.6 BACT for Particulate Matter

4.6.1 Pulverized Coal-fired Boilers

4.6.1.1 Formation of Particulate Matter

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the pulverized coal-fired boilers as a result of entrainment of incombustible inert matter (ash) and condensable substances such as acid gases. Both particulate matter (PM), and particulate matter smaller than 10 micrometer diameter (PM_{10}) require the application of BACT under the Federal PSD program. Particulate matter is total filterable particulate matter as determined by EPA Method 5 or 17. PM_{10} includes filterable particulate matter smaller 10 micrometer diameter as determined by EPA Method 201 or 201A and condensable particulate matter as determined by EPA Method 202.

4.6.1.2 Ranking of Available Particulate Control Technology Options

PM_{10} emission limits are difficult to assess as many listings in the BACT/LAER Clearinghouse and even in issued permits do not specify test methods. Consequently, ENSR has determined that many emission limits only reflect filterable PM or PM_{10} and do not include condensable PM_{10}. The permit for AES-Puerto Rico addressed this issue in detail. AES's permit limits filterable PM_{10} to 0.015 lb/MMBtu and allows stack testing to determine an achievable PM_{10} emission limit. Stack tests showed that filterable PM_{10} emissions were below 0.015 lb/MMBtu. However, based on stack test results, AES has applied for an administrative change to their permit to set the total PM_{10} emission limit at 0.03 lb/MMBtu. The permits for Energy Services of Manitowoc (a small CFB) contains a limit of 0.011 lb/MMBtu, purported to include front and back half PM_{10}. The actual permit for this facility does not specify compliance test method, however, and ENSR believes that the permit limit is intended to include filterable PM_{10} only. This project has yet to be built or tested and its ability to comply with front and back half PM_{10} limits is undetermined. Several other recent coal-fired boiler projects are listed with emission rates in the range of 0.010 lb/MMBtu to 0.015 lb/MMBtu based on front half (filterable) PM only, and this level is representative of BACT and LAER for PM. BACT and LAER for PM_{10} must account for additional emissions attributable to condensable PM_{10}.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of particulate control that may be achieved for pulverized boilers. Emission levels and control technologies have been identified and ranked in Table 4-5.

There are almost 50 coal-fired boilers listed in the EPA's BACT/LAER Clearinghouse with emission limits for filterable particulate matter that are less than or equal to 0.02 lb/MMBtu. All but one of these listings report that a fabric filter is utilized (the AES Puerto Rico facility is the only exception). The control of PM using fabric filtration is clearly demonstrated for coal-fired boilers.

Wet control techniques (venturi or other high-energy scrubbers), on the other hand, do not represent a recently applied or demonstrated control technique for coal-fired boilers and do not offer more stringent levels of control of particulate matter than fabric filters.

Table 4-5
Ranking of Particulate Control Technology Options for Pulverized Coal-fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasibility for Pulverized Coal-fired Boilers?
Fabric Filter	0.01 to 0.02 for filterable PM	Yes
Electrostatic precipitator	0.015 to 0.025 for filterable PM	Yes
High energy wet scrubber	Not determined	No applications in the last 15 years to large coal-fired boilers
Emission levels represent target steady-state values at base load, for front-half (filterable) only. Inclusion of the condensable fraction is anticipated to double the particulate emission rate for coal-fired boilers.		

4.6.1.3 PM and PM_{10} Control Technology Discussion

Fabric Filter

Fabric filters are widely used for particulate control from PC boilers and are capable of over 99% control efficiency. According to EPA's Fabric Filter Fact sheet (EPA, 2000), "flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 13 to 31 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

The advantages of fabric filters include:

1) High collection efficiency for a broad range of particle sizes;
2) Flexibility in design (various methods of cleaning methods and filter media);
3) Wide range of volumetric capacities;
4) Reasonable pressure drops and power requirements; and

5) Handles a wide range of solid materials.

Some disadvantages of fabric filters are as follows:

1) Danger of explosion in the presence of a spark; or catastrophic bag damage due to fire; and
2) Wet particles can agglomerate on a filter cloth if the waste gases are at a temperature close to their dew point.

4.6.1.4 Summary of PC Boiler BACT for Particulate Matter

Fabric filters and electrostatic precipitators (ESP's) represent technically feasible options for the control of particulate matter from coal-fired boilers. Wet control techniques (scrubbers), on the other hand, do not represent a demonstrated control technique and do not offer more stringent levels of control of particulate matter than fabric filters. ESP's are generally less effective at controlling fine particulate, and are generally incapable of any additional control of other pollutants such as acid gases or mercury, and are not considered to represent the top level of available control technology.

Based on numerous projects using fabric filters, Steag proposes to use a fabric filter as BACT to limit PM emissions to 0.010 lb/MMBtu. In addition, Steag proposes to limit total PM_{10} (including condensable PM_{10}) emissions to 0.02 lb/MMBtu. Very little data are available on condensable PM_{10} emissions from western coal (or any) coal-fired boilers, and for that reason Steag proposes a condensable PM_{10} limit of 0.02 lb/MMBtu as BACT for total PM_{10}, but requests a trial period of three years to determine the feasibility of this exceptionally low limit. The proposed PM emission rate is lower than the lowest emission level for a PC unit (Wygen 2 in Wyoming) listed in EPA's RACT/BACT/LAER Clearinghouse.

4.6.2 Auxiliary Boilers

The project includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBtu/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBtu/year, which is equivalent to an average of 550 hours/year per boiler at full load. Proposed BACT limits for PM and PM_{10} are based on the use of very low sulfur distillate oil, the total annual fuel limitation of 142,560 MMBtu/year, and EPA emission factors published in AP-42 and EPA's RACT/BACT/LAER Clearinghouse (see Attachment 2). For PM, BACT for the auxiliary boilers is the annual fuel limitation, the use of 0.05% sulfur distillate oil, and an emission limit of 0.014 lb/MMBtu based on the EPA emission factor of 2 lb/1000 gal. For PM_{10}, BACT includes an emission limit of 0.024 lb/MMBtu based on adding the condensable PM_{10} emissions of 0.01 lb//MMBtu (1.3 lb/1,000 gal based on AP-42) to the PM emission rate.

4.6.3 Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. BACT emission limits include the 100 hour per year (each) operating restriction, and limits of 0.19 g/hp-hr and 0.22 g/hp-hr PM and PM_{10}, respectively, based on EPA emission factors in AP-42.

4.6.4 Material Handling Sources

Material handling sources will be controlled by dust suppression systems, enclosures and/or fabric filters. For example, conveyors will be constructed of enclosed design in order to eliminate wind-blown dust emissions. Conveyors will lead to transfer towers, bunkers or silos that will include a "coal drop". Such structures will also be of enclosed design and will be evacuated (when operating) through fabric filter units, sometimes referred to as "bin vent filters". Enclosed design of materials handling system and evacuation through bin vent filters represents BACT for material handling equipment.

As discussed in Section 3.4, coal handling systems will be subject to NSPS Subpart Y and limestone handling systems will be subject to NSPS Subpart OOO. A review of the EPA RACT/BACT/LAER Clearinghouse (see Attachment 2) gives a range of control efficiencies from baghouses. Although the most recent permits for coal fired power plants, Bull Mountain and Roundup Power Projects, determined that BACT was 0.01 gr/dscf for all sources, the Mid America permit identified 0.005 gr/dscf for baghouses associated with coal sources and 0.01 gr/dscf for other material handling activities. Steag proposes to also specify these filterable PM/PM_{10} emissions limits of 0.005 gr/dscf for coal and 0.01 gr/dscf for limestone and other materials.

We note that as a mine-mouth power plant, the Desert Rock Energy Facility will avoid fugitive dust emissions associated with rail unloading operations and active on-site storage piles. The inactive storage pile will be covered with soil, geotextile or chemical crusting agents to prevent both weathering of the coal and fugitive dust emissions. When coal is added to or reclaimed from the inactive pile, which is expected to be very infrequently, the coal will be wetted and/or treated with chemical agents to minimize any emissions of fugitive dust. These operational measures, and those of the NSPS for coal handling operations (Subpart Y), represent BACT for inactive storage and associated coal handling operations.

4.7 BACT for Sulfuric Acid Mist

4.7.1 Pulverized Coal-fired Boilers

Emissions of sulfuric acid mist are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. The amounts of sulfur or SO_2 that are oxidized to sulfuric acid mist may be affected by trace metal catalysis.

The Thoroughbred Project in Kentucky has proposed a wet electrostatic precipitator (WESP) downstream of a wet scrubber, primarily for additional control of sulfuric acid mist. We note that this project exhibits high uncontrolled sulfuric acid mist emission levels because it will utilize a relatively high sulfur eastern coal. The proposed Desert Rock Energy Facility, by comparison, will have uncontrolled sulfuric acid mist levels that are only a fraction of Thoroughbred's levels.

Steag recognizes, however, that sulfuric acid mist is a precursor to the formation of regional haze, and challenged it's affiliated German engineers (Encotec) to include active control of sulfuric acid mist in the design of the Desert Rock Energy Facility. As a result, an additional stage of acid gas removal using hydrated lime (a technology that is proprietary to Encotec) has been included upstream of the fabric filter to remove sulfuric acid mist before it ever enters the wet scrubber.

The application of this technology will result in emission levels lower than those permitted for Thoroughbred (with an add-on WESP), and represents a level beyond BACT at a sulfuric acid mist emission rate of 0.004 lb/MMBtu.

4.7.2 Auxiliary Boilers and Diesel Generators

No control alternatives beside the use of very low sulfur fuels have been identified for industrial boilers or emergency diesel generators. BACT for sulfuric acid mist for the proposed auxiliary boilers and emergency diesel engines is the use of low sulfur (0.05% S) distillate oil.

4.8 BACT for Hydrogen Fluoride

Emissions of hydrogen fluoride are generated in fossil fuel-fired sources from the oxidation of fluorine present in the fuel. For the PC boilers, the same proprietary acid gas pre-control technology designed by Encotec will control hydrogen fluoride emissions through the injection of hydrated lime before the fabric filter, with additional removal expected from the wet limestone scrubbing. Steag is proposing a hydrogen fluoride emission rate of 0.00024 lb/MMBtu based on an assumed concentration of fluorine in the coal of 100 ppm (estimated 98% control) as BACT. This emission rate is consistent with or lower than all recent BACT decisions.

No appreciable HF is emitted from distillate oil-fired industrial auxiliary boilers or emergency diesel engines, and the use of low fluorine bearing fuel (very low sulfur distillate oil) represents BACT for HF for these emission sources.

4.9 BACT for Lead

Emissions of lead are generated in fossil fuel-fired sources from the impurities present in the fuel. Since lead is emitted as solid particulate from coal-fired boilers, it is already included in the PM and PM_{10} emission selected as BACT. BACT for lead emissions from the proposed PC boilers is the control of PM emissions using fabric filtration (baghouse), and the emission limits determined to represent BACT for PM_{10}.

For distillate oil-fired industrial auxiliary boilers and emergency diesel engines, the use of low ash fuel such as distillate oil represents BACT.

4.10 Summary of BACT Emission Levels

The BACT levels determined through this evaluation for the Desert Rock Energy Facility are summarized in Tables 4-6 and 4-7.

Table 4-6
Summary of Proposed BACT Emission Limits for PC and Auxiliary Boilers

Pollutant	Emissions Limit (lb/MMBtu)	Control Technology
Pulverized Coal-fired Boilers		
NO_x	0.06, 24-hour average, based on continuous emission monitoring	Low-NO_x burners and SCR
SO_2	0.06, 24-hour average, based on continuous emission monitoring	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurization
CO	0.10, 24-hour average, based on continuous emission monitoring	Good combustion practices
VOC	0.003, based on EPA Methods 25A and 19	Good combustion practices
PM	0.01, based on EPA Method 5[1]	Baghouse
PM_{10}	0.02 (total)[2], based on EPA Methods 201 or 201A and 202[3]	Baghouse
Pb	No limit	Baghouse
H_2SO_4	0.004, annual average, based on EPA Method 8	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurization
HF	0.00024, annual average, based on EPA Method 13B	Hydrated lime injection before the fabric filter, and wet limestone desulfurization
Auxiliary Boilers		
NO_x	0.10	Low-NO_x burners
SO_2	0.05	Low sulfur distillate oil (0.05% S)
H_2SO_4	0.00087	Low sulfur distillate oil (0.05% S)
CO	0.036	Good combustion
VOC	0.0024	Good Combustion
PM	0.010[1]	Low sulfur distillate oil and good combustion
PM_{10}	0.024[3]	Low sulfur distillate oil and good combustion

1. PM is defined as filterable particulate matter as measured by EPA Method 5.
2. Since insufficient information exists regarding whether this low limit is achievable, Steag proposes a three year demonstration test period.
3. PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. Because PM_{10} includes condensable particulate matter and PM does not include condensable particulate matter, PM_{10} emissions are higher than PM emissions.

Table 4-7
Summary of Proposed BACT Emission Limits for Other Sources

Pollutant	Emissions Limit	Control Technology
Emergency Generator and Firewater Pump		
NO_x	6.5 g/hp-hr	Ignition timing retard, turbo-charging and after-cooling
SO_2	0.19 g/hp-hr	Low sulfur distillate oil (0.05% S)
H_2SO_4	0.006 g/hp-hr	Low sulfur distillate oil (0.05% S)
CO	0.5 g/hp-hr	Good combustion
VOC	0.3 g/hp-hr	Good combustion
PM/PM_{10}	0.24 g/hp-hr	Low sulfur distillate oil and good combustion
Materials handling systems		
PM/PM_{10}	0.005 gr/dscf (filterable) for coal handling baghouses and 0.01 gr/dscf (filterable) for other materials	Enclosures, dust suppression, and fabric filters

4.11 Maximum Achievable Control Technology (MACT)

The Desert Rock Energy Facility will be a major source of HAPs. Since the MACT standard for coal-fired boilers has not been finalized, this application presents a hazardous air pollutant control technology analysis, that may be used to comply with case-by-case MACT if ultimately required by Section 112 (g) of the Clean Air Act for control of HAP emissions. We note that EPA has recently proposed an NSPS alternative to regulation under MACT. Should such a Rule be adopted in lieu of an applicable Section 112 MACT Standard, the Desert Rock Energy Facility will be required to meet it. The analysis addresses: (1) non-mercury metallic HAP emissions, (2) mercury emissions, acid gases (hydrogen chloride and hydrogen fluoride), and organic HAPs.

We note that mercury control of emission sources such as coal-fired power plants is standard technology in Germany, and that Steag's engineering affiliate Encotec brings the benefit of this experience to the proposed Desert Rock project. The proposed emission control train has been designed specifically to control mercury and other hazardous air pollutants to extremely low levels, particularly for a facility designed to burn Western coal.

Non-mercury metallic HAPs are emitted as part of the particulate emissions from coal combustion. The proposed Desert Rock Energy Facility will use fabric filter technology to limit PM emissions to 0.01 lb/MMBtu, which is the lowest permitted emission rate for a coal-fired boiler and is, therefore, equivalent to LAER. EPA has used PM emission limits as surrogates for control of HAP metal emissions since a strong correlation exists between metallic HAP emissions and PM emissions.

Therefore, the proposed fabric filter and PM emission rate represent a case-by-case MACT (or equivalent standard) for non-mercury metallic HAPs.

EPA's proposals for mercury control are in a state of flux. However, as a new coal project engineered in Germany, the Desert Rock Energy Facility is being designed to achieve an 80% reduction in mercury based on the mercury and chlorine characteristics of the Navajo Reservation (Western) coal. Contributing mercury reductions will be achieved in the SCR, through injection of adsorbent(s) upstream of the fabric filter, in the filter cake of the fabric filter itself, and finally through humidification, cooling and impingement in the wet flue gas desulfurization system. It is widely thought that additional scrubber additives may become available in the next ten years that may be capable of further reductions.

In any event, Steag Power is proposing state-of-the-art mercury control, which represents case-by-case MACT (or equivalent standard) for control of mercury from burning Western coal. Based on the average expected mercury content of 0.046 ppm and 80% control efficiency, it is expected that mercury emissions will be 8.64×10^{6} lb/MWh as compared to the proposed MACT standard of 20×10^{6} lb/MWh as an annual average.

Hydrogen chloride and hydrogen fluoride will be controlled in two active stages: by the proprietary pre-control technology of injection of sorbents such as hydrated lime before the fabric filer followed by wet flue gas desulfurization. HCl will be controlled to less than 0.003 lb/MMBtu, and control efficiencies of at least 98% for HF are expected. The proposed emissions controls, emission limits and high control efficiencies represent case-by-case MACT (or equivalent standard) as well as top down BACT for HCl and HF.

Organic HAP emissions will be controlled by good combustion to limit CO and VOC emissions. High combustion efficiency as shown by the BACT emission rates for CO and VOC represents MACT (or equivalent standard) as well as top down BACT for organic HAP emissions.

5.0 PROJECT EMISSIONS

Potential criteria pollutant emissions are summarized in Section 5.1. Startup and shutdown emission are discussed in Section 5.2. Potential emissions of hazardous air pollutants are summarized in Section 5.3. Emission rates are based on preliminary plant design data from Steag, Encotec, other vendor data, and EPA emission factors from AP-42. Detailed emission calculations and stack parameters for each source are presented in Attachment 3.

5.1 Criteria Pollutant Emissions

Emissions of all criteria pollutants from all sources are controlled by applying BACT. Maximum annual criteria pollutant emission rates are summarized in Table 5-1. The two 750 MW PC boilers are the primary emission sources.

5.2 Startup and Shutdown Emissions

Start up and shutdown emissions have received much attention in the permitting of combustion turbines, since those sources may exhibit higher mass emissions during start up than during maximum operation. This is generally not the case for coal-fired boilers, which exhibit peak mass emission rates at maximum firing rate. Startup and shutdown procedures for the pulverized coal-fired boilers are designed to provide for equipment protection while minimizing emissions. Initial start up duration after an outage may be dictated by the need to gradually warm up refractory materials, metal surfaces, and the 750 MW steam turbine, and this is normally accomplished with start up fuel (such as oil), auxiliary steam (to help preheat steam-side components) and low load operation. Startups are defined as cold, warm and hot to account for the amount of latent heat still in the boiler. The different starts are defined by the amount of time the boiler has been down. Cold starts are defined as starts after the boiler has been down for more than 72 hours, warm starts more than 8 hours and less than 72 hours and hot starts less than 8 hours. The design time required to safely bring each boiler up is defined below. A failed start sequence or "trip" could require longer duration.

- 6.5 hours for a cold start;
- 4.0 hours for a warm start; and
- 2.6 hours for a hot start.

It is just as important not to cool the boiler down too fast. A normal shutdown will require 3-4 hours.

The maximum number of startups is anticipated to be 60 per year, an average of 30 per boiler (4 cold, 10 warm and 16 hot). Startup and shutdown operations do not result in any excess daily or annual emissions compared to normal continuous operation. Thus, Desert Rock Energy Facility does not request any additional limits (beyond maximum allowable mass emission limits) to govern operations during start up and shutdown.

Table 5-1
Summary of Criteria Pollutant Maximum Potential Emissions

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Storage Tanks (tpy)	Project PTE (tpy)
CO	5,526	2.55	0.17	0.031	n/a	n/a	5,529
NO_x	3,315	7.13	2.26	0.41	n/a	n/a	3,325
SO_2	3,315	3.61	0.068	0.012	n/a	n/a	3,319
PM[1]	553	1.02	0.083	0.015	16.1	n/a	570
PM_{10}[2]	1,105	1.68	0.077	0.014	12.9	n/a	1,120
VOC	166	0.17	0.11	0.019	n/a	0.14	166
Lead	11.1	0.00064	0.000012	0.0000022	n/a	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	neg	13.3
H_2SO_4	221	0.062	0.002	0.0004	n/a	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	n/a	0.057
Hydrogen Sulfide	neg	neg	neg	neg	n/a	n/a	neg
Total Reduced Sulfur	neg	neg	neg	neg	n/a	n/a	neg
Reduced Sulfur Compounds	neg	neg	neg	neg	n/a	n/a	neg

n/a – not applicable, neg. – negligible

1. PM is defined as filterable particulate matter as measured by EPA Method 5.
2. PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. Because PM_{10} includes condensable particulate matter and PM does not include condensable particulate matter, PM_{10} emissions are higher than PM emissions.

The facility design also includes three 86.4 MMBtu/hour boilers, equipped with superheaters, burning low sulfur distillate oil (0.05% sulfur) to provide steam to assist with reducing the time for startup of the main boilers by preheating key areas. When the flue gas temperature of the PC boilers exceeds 600°F (320°C), which typically approximates a boiler load of 40%, the SCR system is placed in service and startup is complete. The SCR will not function at temperatures below 600°F (320°C).

During a cold start, two auxiliary boilers will start providing steam to the main boiler and/or the steam turbine at least one hour before any fuel is fired in the main boiler. For the next 4.5 hours, boiler equipment will be gradually warmed up using steam from the auxiliary boilers and by firing low sulfur distillate oil (0.05%) in the main boiler. During the last hour, an auxiliary boiler will continue to operate while pulverized coal feeding is started and gradually increased until the boiler reaches 40% load completing startup.

A warm start requires less time than a cold start because the equipment is hotter and thermal stresses are reduced. For a warm start, two auxiliary boilers will start providing steam to the main boiler and/or the steam turbine approximately one hour before any fuel is fired in the main boiler. For the next 2 hours, boiler equipment will be gradually warmed up using steam from the auxiliary boilers and by firing low sulfur distillate oil (0.05%) in the main boiler. During the last hour, an auxiliary boiler will continue to operate while pulverized coal feeding is started and gradually increased until the boiler reaches 40% load completing startup.

A hot start only requires 2.6 hours because the equipment is relatively hot and thermal stresses are reduced. A hot start begins with firing of low sulfur distillate oil in the main boiler. After approximately 5 minutes, two auxiliary boilers will start providing steam to the main boiler and/or the steam turbine. After about one hour, feeding of pulverized coal will be started. For the remaining 1.6 hours, the coal feed rate will be gradually increased while the auxiliary boiler load and oil firing rate to the main boiler are decreased. During a hot start, average hourly emissions of all pollutants, except for NO_x, are less than normal full load emissions. The slightly elevated NO_x emission rates during startup are of a short duration and do not result in any long-term increase in emissions compared to normal continuous operation.

For a routine shutdown, an auxiliary boiler begins providing steam approximately 15-20 minutes before the coal feed rate is decreased below 40% load. At 40% load, the SCR is taken out of service. The coal feed rate is gradually decreased to 0% over a two-hour period. Toward the middle of this period, oil firing in the main boiler is started and the auxiliary boiler continues to operate. After coal feeding stops, oil firing continues in the main boiler for about 0.5 hours. During a shutdown, average hourly mass emissions of all pollutants are less than normal full load emissions.

5.3 Hazardous Air Pollutant Emissions

Emissions of HAPs are controlled by applying BACT as well as technology that would also qualify as MACT. Maximum annual HAPs emission rates are summarized in Table 5-2. Maximum emissions for all HAPs from the project are 227.8 tons/year with the pulverized coal-fired boilers accounting for 227.2 tons/year. Hydrogen chloride emissions of 166 ton/year and hydrogen fluoride emissions of 13.3 tons/year account for most of the emissions from the pulverized coal-fired boilers. Maximum mercury emissions are estimated to be less than 0.06 tons/year.

Table 5-2
HAP Emissions Summary

Emissions Unit	HAP Emissions (tpy)
Main Boilers	227.8
Auxiliary Boilers	0.0037
Emergency Generators	0.0020
Diesel Fire Pumps	0.0009
Total Facility HAP Emissions (tpy)	**227.8**

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 Overview

This Section of the PSD application addresses all PSD requirements related to air quality and air quality related values impact analyses. The location of the Desert Rock Energy Facility is approximately 25 - 30 miles (40 – 60 km) southwest of Farmington, New Mexico in the Four Corners Area where Arizona, Colorado, New Mexico and Utah meet. It is a region that contains a significant number of National Parks and Wilderness Areas, some of which have been designated as PSD Class I areas. Steag and ENSR have worked closely with EPA and the Federal Land Managers (FLMs) from both the National Park Service (NPS) and the USDA Forest Service, as well as other Navajo Nation, State and Federal agencies, to perform the analyses for determining the potential for air quality impacts from this Project.

A slightly revised modeling protocol is provided in Attachment 4 and it describes the dispersion modeling procedures for determining the air quality impact of the proposed facility on nearby PSD Class I and II areas. A review of the modeling procedures is presented in Section 6.2. The PSD Class II modeling analysis consists of two components:

1) A “near-field” Class II modeling analysis to determine maximum impacts in the vicinity of the Desert Rock Energy Facility, and
2) A “distant” Class II modeling analysis that reviewed impacts at areas identified by the FLMs that do not qualify for Class I protection under the Clean Air Act.

The near-field Class II and distant Class II modeling analysis and results are described in Sections 6.3 and 6.4, respectively. Next the results of the analyses performed, including increment analyses, visibility and acid deposition assessments, for the Class I areas are given in Section 6.5. For those impacts that were modeled to be over a significant impact criteria, cumulative analyses are provided in the appropriate sections. Section 6.6 discusses additional impact analyses, such as a growth assessment, soils and vegetation analysis, ozone impact review, and other impact issues. The results of all the evaluations are then summarized in Section 6.7. The analyses conclude that operation of the Desert Rock Energy Facility will not have a significant adverse impact on air quality or related values in this region.

6.2 Modeling Procedures

As discussed in the modeling protocol, ENSR used the CALPUFF modeling system for both the Class I PSD modeling and Class II analyses due to the presence of complex winds in the vicinity of the proposed Desert Rock Energy Facility.

ENSR used the following versions of the CALPUFF modeling system:

- CALMET version 5.2 (level 000602d),
- CALPUFF version 5.5 (level 010730_1), and
- CALPOST version 5.2 (level 991104d).

These software versions are the ones associated with the latest available user guides. Although EPA has announced the availability of 2003 versions of the CALPUFF modeling system, these are still being debugged and do not have any user's guides available.

6.2.1 Meteorological Data

The meteorological data that was used as input to CALPUFF features three years of prognostic mesoscale meteorological (MM) data, as is recommended by the Guideline on Air Quality Models (Section 9.3.1.2(d)). The most advanced MM data was used, consisting of 2001-2003 hourly meteorological data archived from the Rapid Update Cycle (RUC) model. Horizontal data resolution for the RUC model is 40 kilometers for 2001 and 2002, and 20 kilometers for 2003. The Rapid Update Cycle data is referred to as "RUC40" for the 40-km resolution data and "RUC20" for the 20-km resolution data. A technical paper describing a precedent for the regulatory use of this type of data in a North Dakota CALPUFF application is provided in Appendix B of the modeling protocol.

The CALMET modeling conducted for the nearby PSD Class II area used 1.5-km grid spacing, encompassing an area 210-km square. The CALMET modeling for the distant PSD Class II areas and the PSD Class I area encompassed a 680 km x 552 km (E-W / N-S) area with a 4-km grid element size. Details regarding the CALMET modeling are provided in the modeling protocol (Attachment 4).

6.2.2 Stack Characteristics and Emissions

The PSD Class I and II modeling analyses used emission rates presented in Tables 6-1 through 6-4 for the Desert Rock Energy Facility, which characterize emissions from the main stack and other ancillary combustion sources associated with the plant. There are three start-up and one shutdown emissions scenarios for the facility, as described in Section 3 of the modeling protocol. All of the start-up and shutdown emissions are less than minimum load (40% load) case and have not been modeled separately.

CALPUFF has the ability to change the heat input rate as a function of the ambient temperature by using an adjustment factor based on a reference ambient temperature. Steag provided data on the temperature dependence of the heat input rate as shown in Table 6-5 for the 100% load case. These data were used as input to the source characterization to more accurately model the hourly emissions from the main stack at 100% and 40% load cases.

The Class I analysis modeled the main stack only at 100 percent load. A SCREEN3 analysis, provided in Appendix D of the modeling protocol, indicates that the lowest (40%) load case can possibly lead to the highest near-field concentration predictions. Therefore, for the Class II analysis, the main stack at both 40 and 100 percent (maximum and minimum) load for both one and two units operating was modeled, and emissions from the auxiliary boiler, the diesel generator and fire water pump, and the material-handling sources were also included. The material handling sources were conservatively modeled at 0.01 grains per dry standard cubic foot, although the emission points associated with coal handling will be controlled to 0.005 grains per dry standard cubic foot.

Table 6-1
Emission Rates and Stack Parameters for Each of the Main Boilers

Plant Performance	***Units***	**100% Load**	**40% Load**
Full Load Heat Input to Boiler	*MMBtu/hr*	6,810	2,724
Emissions per Boiler			
SO_2 (24-hour average)	*lb/MMBtu*	0.060	0.060
Hourly Emissions	*g/s*	51.5	20.6
NO_X (24-hour average)	*lb/MMBtu*	0.060	0.060
Hourly Emissions	*g/s*	51.5	20.6
PM_{10} Total	*lb/MMBtu*	0.020	0.020
Hourly Emissions	*g/s*	17.2	6.86
CO	*lb/MMBtu*	0.100	0.100
Hourly Emissions	*g/s*	85.8	34.3
H_2SO_4	*lb/MMBtu*	0.0049	0.0049
Hourly Emissions	*g/s*	4.20	1.68
Pb	*lb/MMBtu*	0.00020	0.00020
Hourly Emissions	*g/s*	0.17	0.07
Stack Parameters			
Stack Gas Exit Temperature	F	122	122
	K	**323.15**	**323.15**
Stack Gas Exit Velocity	ft/s	82	32.8
	m/s	**24.99**	**10.00**
Stack Height	ft	917	917
	m	**279.5**	**279.5**
Stack Diameter	ft	36.77	36.77
	m	**11.21**	**11.21**

Table 6-2
Emission Rates and Stack Parameters for Each Auxiliary Steam Generator

Estimated Annual Hours of Operation:	550	hours/year
Stack Height:	98	feet
Stack Diameter:	2.924	feet
Stack Flow Rate:	33,038	cfm
Average Stack Exit Temperature:	284	^oF
Stack Exit Velocity:	82	ft/s

Pollutant	Hourly Emissions			Annual Emissions	
	(lb/hr)	(g/s)	(lb/MMBtu)	(tpy)	(g/s)
CO	3.09	0.39	0.036	0.85	0.024
NO_x	8.64	1.09	0.1	2.38	0.068
PM_{10} Total	2.04	0.26	0.024	0.56	0.016
SO_2	4.38	0.55	0.051	1.20	0.035
H_2SO_4	0.076	0.010	0.00087	0.021	0.0006
Pb	0.00078	0.00010	0.000009	0.00021	0.00006

Table 6-3
Emission Rates and Stack Parameters for Each Emergency Diesel Generator

Maximum Annual Hours of Operation:	100	hours/year
Stack Height:	45	feet
Stack Diameter:	3	feet
Stack Flow Rate:	9058	cfm
Stack Gas Exit Temperature:	870	^oF
Stack Gas Exit Velocity:	21	ft/s

Pollutant	Hourly Emissions			Annual Emissions	
	(lb/hr)	(g/hp-hr)	(g/s)	(tpy)	(g/s)
CO	1.74	0.50	0.22	0.09	2.5E-03
NO_x	22.61	6.50	2.85	1.13	0.033
PM_{10} Total	0.77	0.22	0.10	0.04	1.10E-03
SO_2	0.68	0.19	0.09	0.03	9.72E-04
H_2SO_4	0.02	0.01	0.003	0.00	2.95E-05
Pb	1E-04	3E-05	2E-05	6E-06	1.73E-07

Table 6-4
Emission Rates and Stack Parameters for Each Diesel Fire Water Pump

Maximum Annual Hours of Operation:	100	hours/year
Stack Height:	30	feet
Stack Diameter	0.6	feet
Stack Flow Rate:	1265	cfm
Stack Gas Exit Temperature:	900	^oF
Stack Gas Exit Velocity:	74	ft/s

Pollutant	Hourly Emissions			Annual Emissions	
	(lb/hr)	(g/hp-hr)	(g/s)	(tpy)	(g/s)
CO	0.31	0.50	0.04	1.57E-02	4.5E-04
NO_x	4.07	6.50	0.51	0.204	5.85E-03
PM_{10} Total	0.12	0.19	0.02	6.9E-03	1.98E-04
SO_2	0.12	0.19	0.02	6.08E-03	1.75E-04
H_2SO_4	0.004	0.01	0.0005	1.84E-04	5.3E-06
Pb	2.E-05	3.E-05	3.E-06	1.08E-06	3.12E-08

Table 6-5
Adjustment Factor for 100% Load Heat Input Rate

Emissions, lb/MMBtu				
Temperature		Factor	Heat input	
F	C		MMBtu/hr	MMBtu/hr
<32	<0	0.9230	6,286	12,572
36.5	2.5	0.9299	6,332	12,665
45.5	7.5	0.9343	6,363	12,726
54.5	12.5	0.9398	6,400	12,800
63.5	17.5	0.9465	6,446	12,892
72.5	22.5	0.9528	6,489	12,977
81.5	27.5	0.9609	6,543	13,087
90.5	32.5	0.9698	6,604	13,208
99.5	37.5	0.9869	6,721	13,442
108.5	**42.5**	**1.0000**	6,810	13,620
117.5	47.5	1.0135	6,902	13,804
>122	>50	1.0310	7,021	14,043

6.2.3 Significance Criteria and PSD Increments

In order to determine if impacts could be considered significant, modeling results are compared to Significant Impact Levels (SILs), which act as screening levels to determine if further analysis is required. Table 6-6 provides the PSD Class II and Class I SILs that were used for this application. If impacts are determined to be greater than the SILs, then a cumulative analysis is performed which includes background emission sources that would consume PSD increment. The PSD Class II and Class I increments, which are levels that cannot be exceeded, are also shown in Table 6-6.

Beside a PSD increment consumption analysis, if impacts exceed the relevant SILs, an ambient air quality standards (AAQS) analysis is also needed. The National and New Mexico AAQS were provided in Tables 3-1 and 3-2, respectively.

Table 6-6
Significant Impact Levels and PSD Increments

Pollutant	Averaging Period	Significant Impact Levels		PSD Increments	
		Class II [1] ($\mu g/m^3$)	Class I [2] ($\mu g/m^3$)	Class II ($\mu g/m^3$)	Class I ($\mu g/m^3$)
NO_2	Annual	1	0.1	25	2.5
SO_2	Annual	1	0.1	20	2
	24-hour	5	0.2	91	5
	3-hour	25	1	512	25
PM_{10}	Annual	1	0.2	17	4
	24-hour	5	0.3	30	8
CO	8-hour	500	N/A	N/A	N/A
	1-hour	2,000	N/A	N/A	N/A

1. Not to be exceeded
2. Proposed by EPA (1996; 61 FR 38249)
There are no SILs or PSD Increments for ozone or lead.

6.2.4 Background Source Inventory

As will be described in Sections 6.3 and 6.5, the results of the modeling analyses determined that background source inventory data were needed for SO_2 sources both in the vicinity of the Desert Rock Energy Facility and the Class I areas, and PM_{10} sources were needed in the vicinity of the facility.

The source emissions data were obtained for an area out to 50 kilometers beyond the PSD Class II pollutant-specific Significant Impact Areas (SIAs) for modeling compliance with the Class II increments and the NAAQS. Source data for the PSD Class I areas were obtained from the entire modeling domain, following suggestions by the National Park Service (NPS), provided below. The source information used in the modeling was obtained from several sources (see the modeling archive):

- The National Park Service for three projects in Utah and New Mexico
- The state agencies in Utah, Colorado, Arizona, and New Mexico
- EPA's 1999 National Emissions Inventory
- Aerial/satellite photos, topographic maps, and eyewitness information for the Navajo Nation.

Agency communications and documents relating to the background emissions inventory are provided in the modeling data archive (provided separately).

For the PSD Class II cumulative modeling, all sources, regardless of size, were selected within the SIA itself. Beyond the SIA, all SO_2 sources were modeled except for very small sources with an emission rate in tons per year (tpy) that was smaller than 0.8D, where D is the distance from the SIA in kilometers (km). The 0.8D relationship is based upon a NPS suggestion, and is consistent with a threshold emission rate of 40 tpy at a distance of 50 km. For PM_{10}, the relationship applied was 0.3D. In either case, the relationship is consistent with the PSD significant emission rate threshold at a distance of 50 km. D was calculated based on the center of the circle that encompassed the receptors at which the project is significant. The resulting PSD Class II SO_2 and PM_{10} inventories are provided in Section 6.3.

For the NAAQS analysis, a regional background value was added for SO_2 and PM_{10}. Table 6-7 lists the second-highest short-term and highest annual concentrations observed for each monitor.

Table 6-7
Regional Background Concentrations for NAAQS Analysis

Pollutant	Monitor Site	Averaging Period	Measured Concentrations ($\mu g/m^3$)		
			2000	2001	2002
SO_2	1300 W. Navajo, Farmington, San Juan County ID 35-045-0008-42401-1	3-hour	62.9	65.5	**68.1**
		24-hour	18.3	18.3	**21.0**
PM_{10}	W. Animas, Farmington, San Juan County ID 35-045-0006-81102-1	24-hour	27.0	27.0	**38.0**
		Annual	16.0	17.0	**17.0**

For the PSD Class I cumulative modeling, all PSD sources with emissions of at least 100 tpy were modeled for all applicable Class I areas, regardless of distance, as long as the sources were located inside the modeling domain. In addition, sources of at least 40 tpy between 50 and 100 km of a given Class I area were included, as well as sources larger than 0.8D within 50 km of a Class I area. The additional sources less than 100 tpy were small in number, so all sources were modeled for the Class I areas for simplicity in approach. The PSD Class I inventory for non-project SO_2 sources is provided in Section 6.5.

6.3 Near-field PSD Class II Modeling Analyses

A modeling domain that extends approximately 105 kilometers in all directions from the proposed facility location was used in this near-field Class II CALPUFF modeling analysis, as shown in Figure 6-1. The total domain size of 210 kilometers was chosen because the maximum extent of the SIA is generally considered to be 50 kilometers from the proposed source location, but the high terrain in the Ute Mountains in northern New Mexico was also populated with receptors out to about 55 km. An additional buffer distance of 50 km was provided for inclusion of background sources in a possible cumulative source analysis. This design allows a 210 km x 210 km (E-W / N-S) grid with a 1.5-km grid element size. The southwest corner of the grid is located at approximately 35.55°N latitude and 109.75°W longitude.

6.3.1 Source and Receptor Locations

The proposed facility's central location is noted by the UTM coordinates of the main stack, which are 721,703.3 m (Easting) and 4,040,903.95 m (Northing) (UTM zone 12, North American Datum 1983 [NAD83]). The Lambert Conformal location of this stack is 129.21 km (east) and 54.14 km (north), based on reference coordinates of 36° N latitude and 110° W longitude along with 30° N and 60° N as the two standard parallels. The Class II CALPUFF analysis used receptors based on this Lambert Conformal projection and the main stack as the center of the grid (see Figure 6-2). Figure 6-3 shows the near field receptor grid and fenceline. Receptors were placed along the proposed facility fence line spaced at every 50 meters. A multi-layered Cartesian grid combined with a polar grid extends out from the main stack as far as to resolve the SIA. The Cartesian receptor grid consists of 100-meter spaced receptors beyond the fenceline out to 1.5 km, 250-meter spacing was used beyond 1.5 km out to 4 km, 500-meter spacing was used beyond 4 km out to 8 km, and 1000-meter spacing was used beyond 8 km out to 10 km. Beyond 10 km, polar grid receptors were used. The polar grid receptors were placed along 36 10^{o} radials extending from the central location of the main stacks. Receptors between 10 km and 20 km were placed along each radial every 1000 meters, and from 20 km to 50 km, 5000-meter spacing were used. Additional densely spaced receptors were placed in one specific area with complex terrain (in the Ute Mountains to the north, in the direction where the proposed facility, the Four Corners Power Plant, and the San Juan Generating Station line up) to ensure resolution of the maximum impacts in that area. The near-field receptor elevations were developed from 7.5 minute (~30 meter spaced) and 10-meter spaced Digital Elevation Model (DEM) files. The polar coarse grid receptors were developed from 90-meter spaced DEM files.

Figure 6-1 Class II CALPUFF Modeling Domain

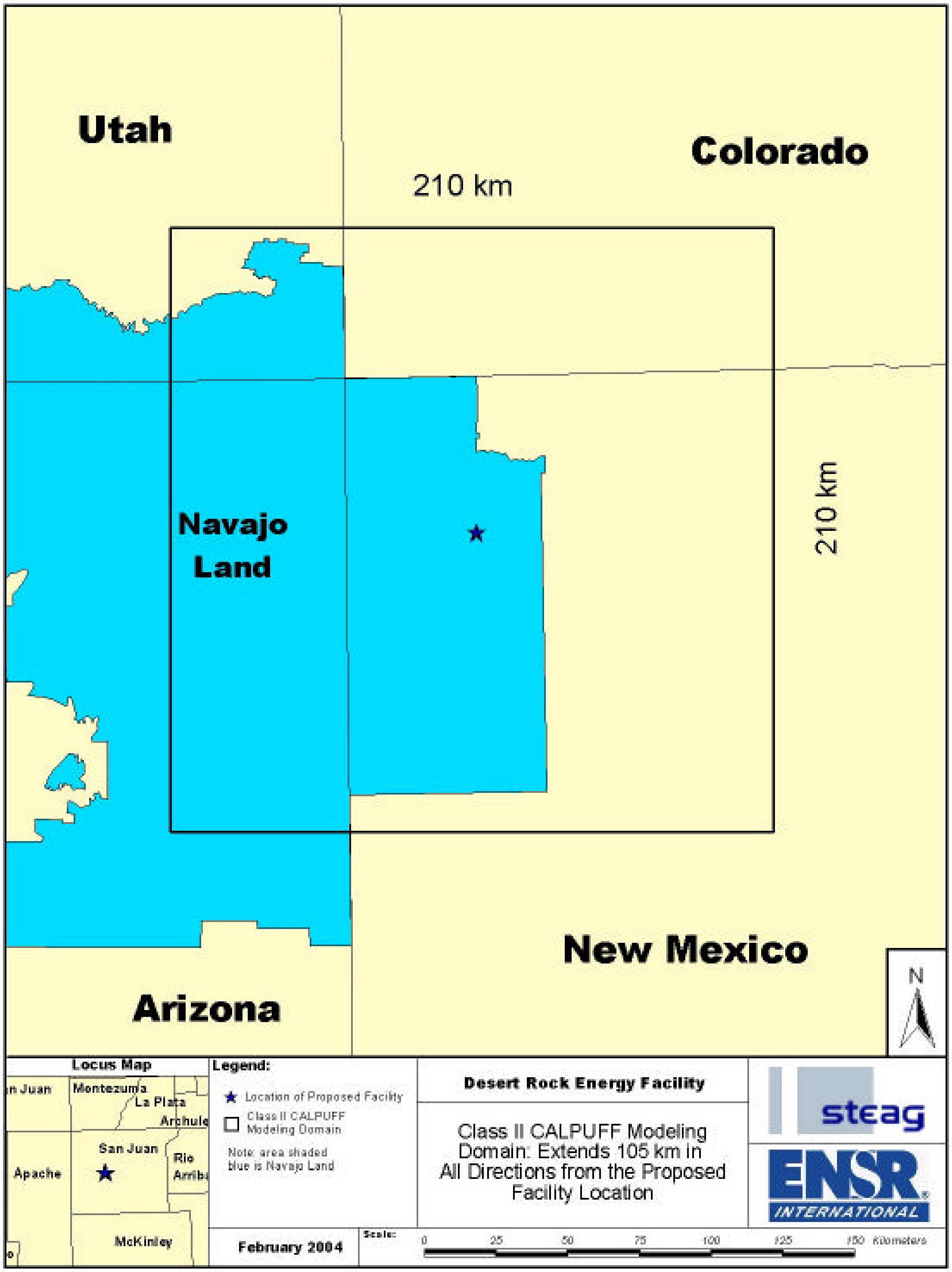


Figure 6-2 Class II Receptor Grid

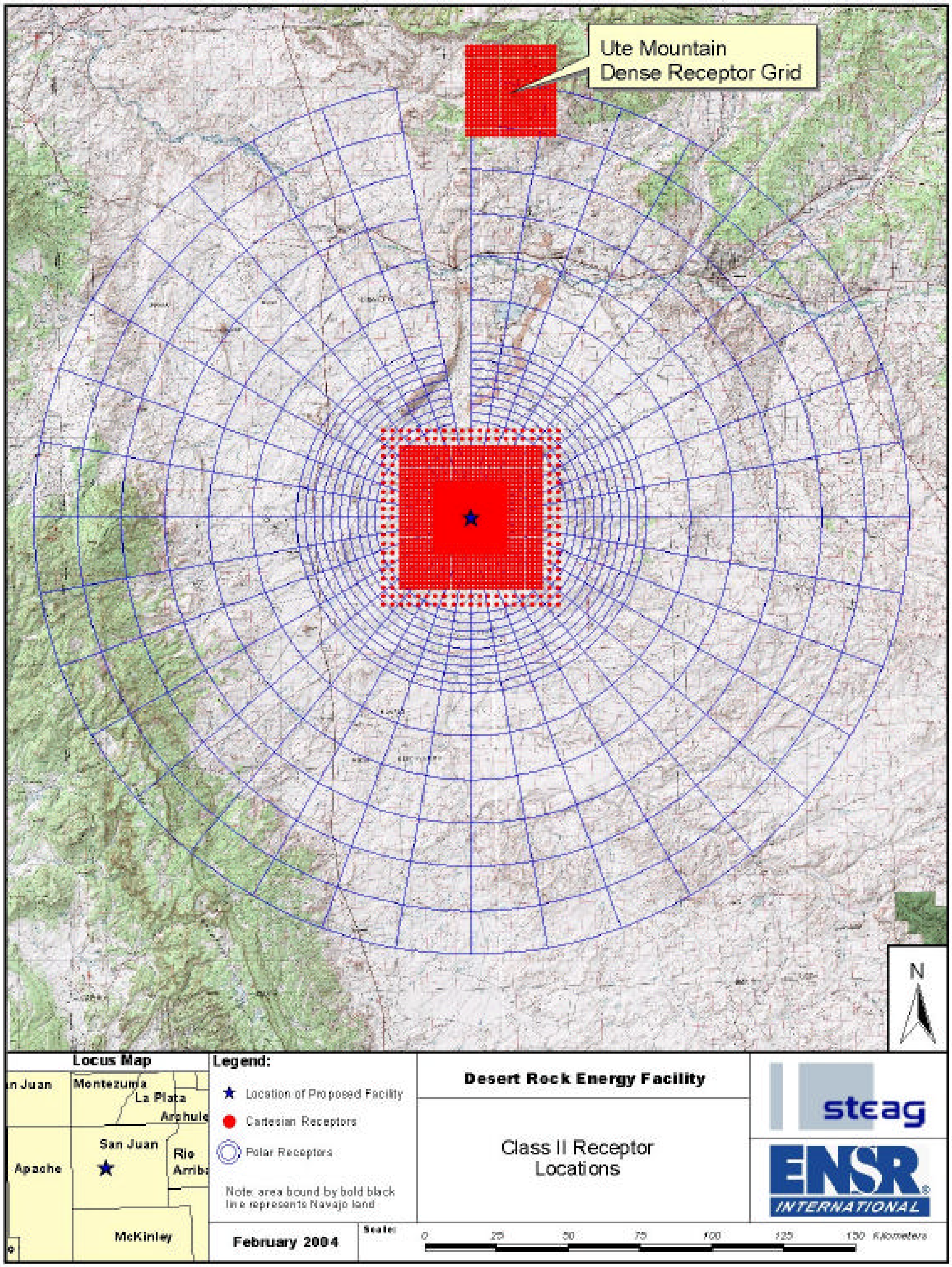
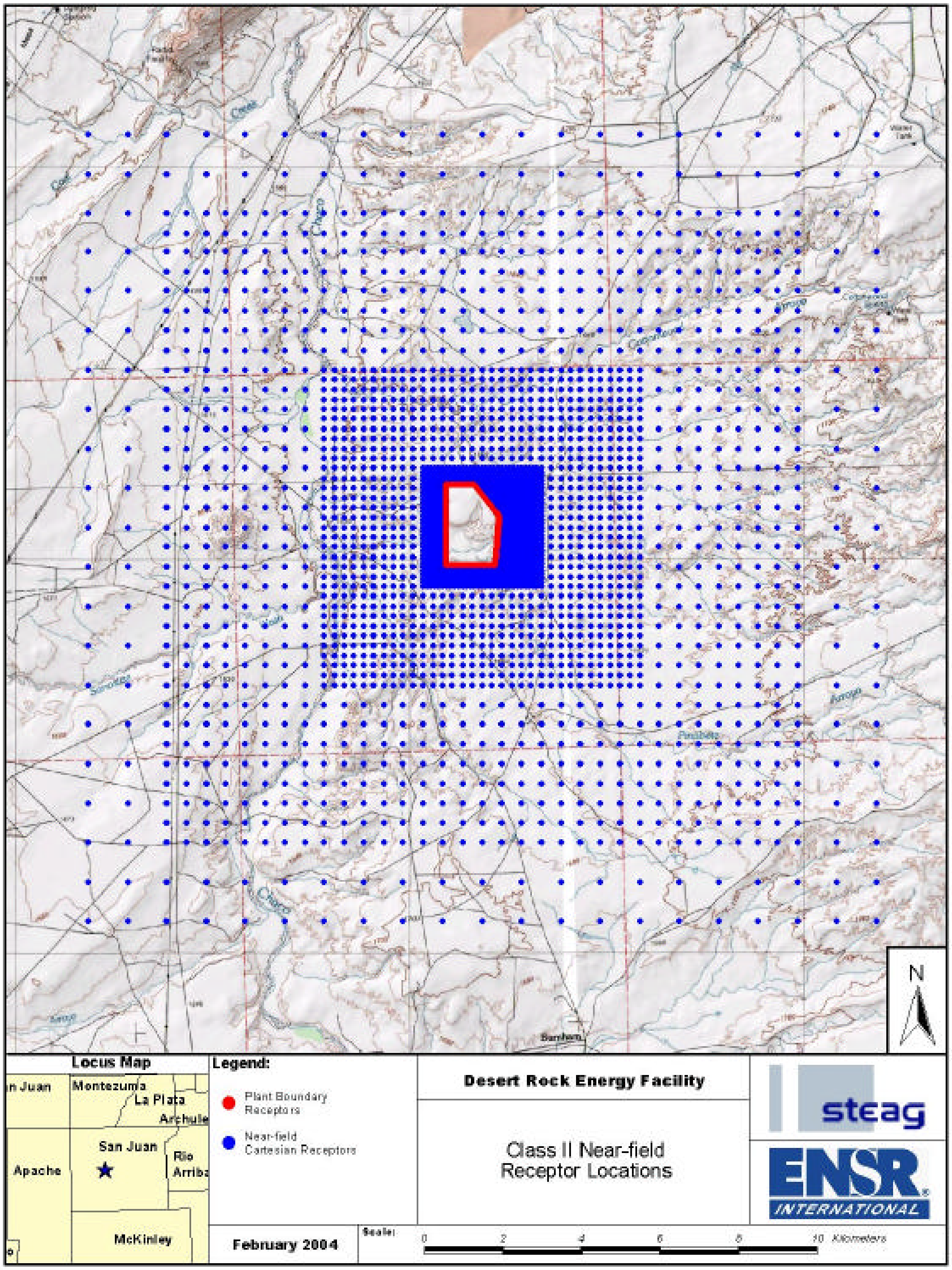


Figure 6-3 Near-Field Receptor Grid



6.3.1.1 Good Engineering Practice Stack Height Analysis

Federal stack height regulations limit the stack height used in performing dispersion modeling to predict the air quality impact of a source. Sources must be modeled at the actual physical stack height unless that height exceeds the Good Engineering Practice (GEP) stack height. If the physical stack height is less than the formula GEP height, the potential for the source's plume to be affected by aerodynamic wakes created by the building(s) must be evaluated in the dispersion modeling analysis.

A GEP stack height analysis was performed for all point emission sources that are subject to effects of buildings downwash at the proposed facility in accordance with the EPA's "Guideline for Determination of Good Engineering Practice Stack Height" (EPA, 1985). A GEP stack height is defined as the greater of 65 meters (213 feet), measured from the ground elevation of the stack, or the formula height (H_g), as determined from the following equation:

$$H_g = H + 1.5\ L$$

where

H is the height of the nearby structure which maximizes H_g, and

L is the lesser dimension (height or projected width) of the building.

Both the height and the width of the building are determined through a vertical cross-section perpendicular to the wind direction. In all instances, the GEP formula height is based upon the highest value of H_g as determined from H and L over all nearby buildings over the entire range of possible wind directions. For the purposes of determining the GEP formula height, only buildings within 5L of the source of interest are considered.

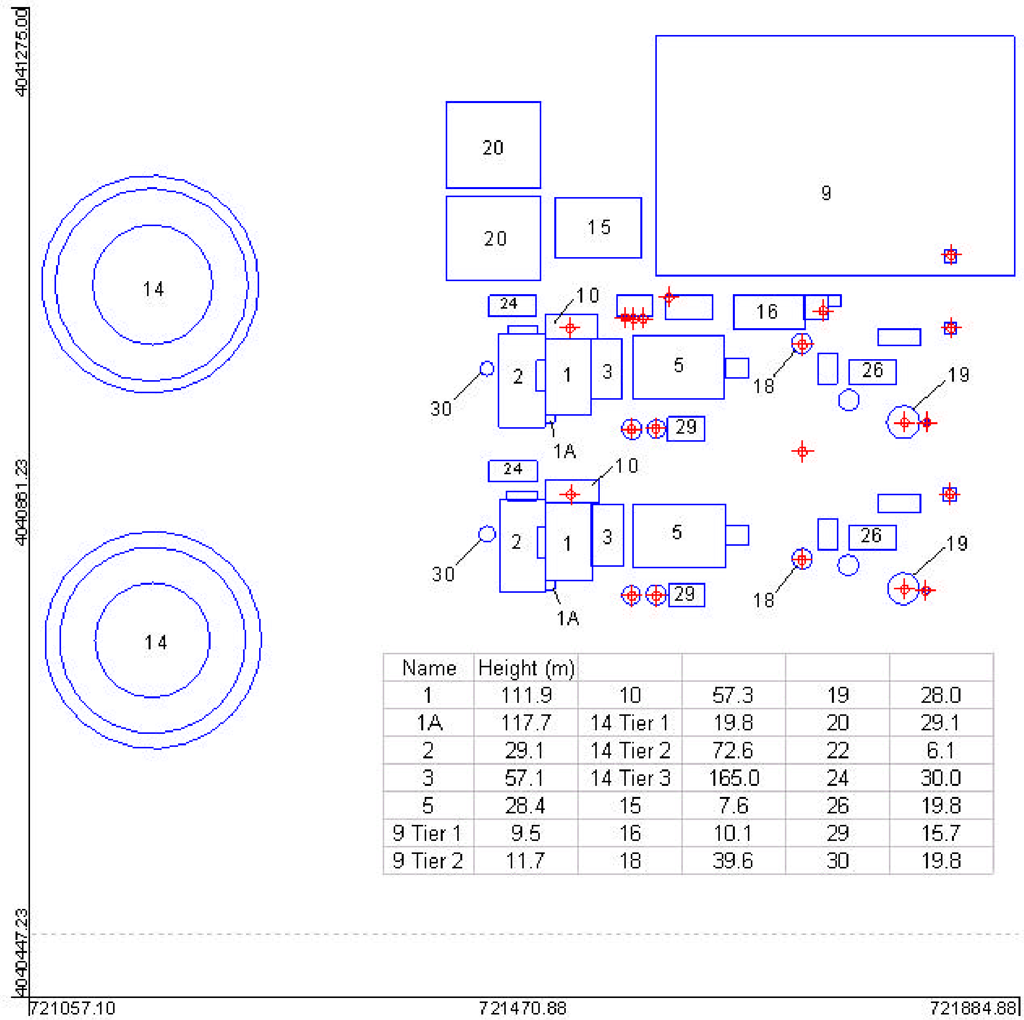
The GEP analysis was conducted with EPA's BPIP program, version 95086. The building-specific wind directions were used as input to CALPUFF. Figures 6-4 and 6-5 show the buildings and stacks considered in the GEP analysis. The steam generator buildings (Building 1 in Figure 6-4) located west of the main stack were the determinants in this analysis. Each of these two buildings is 367 feet tall and 213 long. The BPIP program combines these two buildings as a squat structure and uses the formula H_g = 2.5 x H. In this case the GEP stack height is 917 feet. The gray areas in Figure 6-5 represent the areas modeled for the road network. The main stack of 917 feet is at GEP height, therefore no building dimensions were included in CALPUFF for the main stack.

A review of the distances between each source and controlling building and the plant fenceline indicated that all potential building cavities that affect stacks would be wholly contained within the plant property. As a result, no further analysis of building cavity effects is necessary.

Figure 6-4 GEP Analysis Building Heights and Locations

PROJECT TITLE:

Building Heights and Locations



Name	Height (m)				
1	111.9	10	57.3	19	28.0
1A	117.7	14 Tier 1	19.8	20	29.1
2	29.1	14 Tier 2	72.6	22	6.1
3	57.1	14 Tier 3	165.0	24	30.0
5	28.4	15	7.6	26	19.8
9 Tier 1	9.5	16	10.1	29	15.7
9 Tier 2	11.7	18	39.6	30	19.8

COMMENTS:

Revised Locations of Stacks and Buildings for the STEAG Project

BUILDINGS:

55

SOURCES:

21

Wind Direction:

COMPANY NAME:

ENSR International

MODELER:

Mary M. Kaplan

0 0.1 km

DATE:

4/15/2004

PROJECT NO.:

09417-360-0241

ENSR INTERNATIONAL

BPIP View - Lakes Environmental Software

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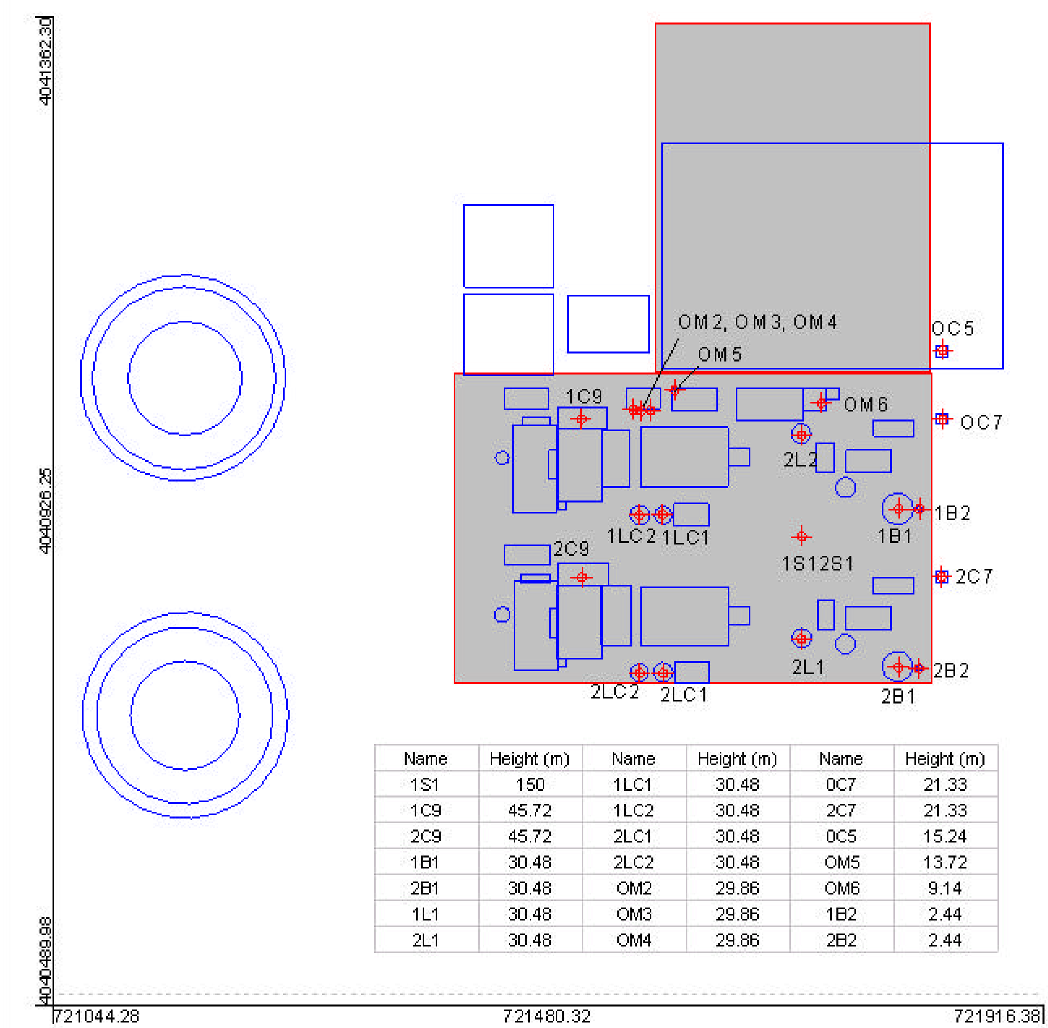
Figure 6-5 GEP Analysis Stack Heights and Locations

PROJECT TITLE:
Stack Heights and Locations



Name	Height (m)	Name	Height (m)	Name	Height (m)
1S1	150	1LC1	30.48	0C7	21.33
1C9	45.72	1LC2	30.48	2C7	21.33
2C9	45.72	2LC1	30.48	0C5	15.24
1B1	30.48	2LC2	30.48	OM5	13.72
2B1	30.48	OM2	29.86	OM6	9.14
1L1	30.48	OM3	29.86	1B2	2.44
2L1	30.48	OM4	29.86	2B2	2.44

COMMENTS:
Revised Locations of Stacks and Buildings for the STEAG Project

BUILDINGS:
55

COMPANY NAME:
ENSR International

SOURCES:
21

MODELER:
Mary M. Kaplan

Wind Direction:

0 0.1 km

DATE:
4/15/2004

PROJECT NO.:
09417-360-0241

BPIP View - Lakes Environmental Software

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6.3.2 Near-field Project Only Class II Modeling Results

Results of the near-field (within 55 km) PSD Class II increment modeling from proposed Desert Rock Energy Facility emissions are provided in Tables 6-8a and 6-8b. The results indicate the following:

- The project emissions have a significant impact for SO_2 and PM_{10}, and an insignificant impact for CO and NO_x.
- The project impacts are below the PSD increments. Most of the peak air quality impacts are within 1 kilometer of the plant fenceline, so there is little likelihood for interaction with other sources in the area.
- The following Significant Impact Area distances resulted:
  - 11.0 km for SO_2, and
  - 1.7 km for PM_{10}.
- The project has an insignificant impact for all pollutants modeled in areas outside the Navajo Nation, including the area to the north in the Ute Mountains.

Table 6-8a
Maximum Predicted Air Quality Impacts from the Proposed Project: Navajo Nation

Pollutant	Averaging Period	Maximum Modeled Conc. (µg/m^3)	Distance (km)	Bearing (Deg.)	SIL (µg/m^3)	% of SIL	PSD Class II Increment (µg/m^3)	% of Incr.	NAAQS (µg/m^3)	% of Ambient Standard
NO_X	Annual	0.62 [1]	1.0	307	1	62%	25	2%	100	1%
SO_2	3 hour [2]	130.60	1.1	129	25	522%	512	26%	1,300	10%
	24 hour	16.35	0.6	44	5	327%	91	18%	365	4%
	Annual	0.65	3.3	130	1	65%	20	3%	80	1%
PM_{10}	24 hour	10.16	0.6	40	5	203%	30	34%	150	7%
	Annual	2.04	0.5	19	1	204%	17	12%	50	4%
CO	1 hour	427.47	1.1	129	2000	21%	N/A	N/A	40,000	1%
	8 hour [3]	145.01	1.1	129	500	29%	N/A	N/A	1,000	15%
Pb	Quarterly	0.04	1.1	129	N/A	N/A	N/A	N/A	2	3%

1. National default ratio of 0.75 for NO_2/NOx used.
2. For 3-hour averages, an SO_2 emission rate of 0.09 lb/MMBtu was assumed to account for short term variability.
3. CALPUFF does not provide 8-hour average results, so a conservatively high 3-hour average is provided for CO.

Table 6-8b
Maximum Predicted Air Quality Impacts from the Proposed Project: New Mexico

Pollutant	Averaging Period	Maximum Modeled Conc. (µg/m^3)	Distance (km)	Bearing (Deg.)	SIL (µg/m^3)	% of SIL	PSD Class II Increment (µg/m^3)	% of Incr.	NAAQS (µg/m^3)	% of Ambient Standard
NO_X	Annual	0.14	24.5	110	1	14%	25	1%	100	0%
	24 hour [1]	1.56	24.6	20	N/A	N/A	N/A	N/A	N/A	N/A
SO_2	3 hour [2]	9.26	24.6	20	25	37%	512	2%	1,300	1%
	24 hour	1.46	24.6	20	5	29%	91	2%	365	0%
	Annual	0.13	24.5	110	1	13%	20	1%	80	0%
PM_{10}	24 hour	0.53	24.6	20	5	11%	30	2%	150	0%
	Annual	0.06	24.5	110	1	6%	17	0%	50	0%
CO	1 hour	13.96	24.5	100	2000	1%	N/A	N/A	40,000	0%
	8 hour [3]	10.27	24.6	20	500	2%	N/A	N/A	10,000	1%
Pb	Quarterly	0.005	24.6	20	N/A	N/A	N/A	N/A	2	0%

1. A 24-hour State of New Mexico NOx standard applies for receptors outside of the Navajo Nation.
2. For 3-hour averages, an SO_2 emission rate of 0.09 lb/MMBtu was assumed to account for short-term variability.
3. CALPUFF does not provide 8-hour average results, so a conservatively high 3-hour average is provided for CO.

6.3.3 Near-field Cumulative Class II Modeling Results

As described above, the project only impacts were significant in the near-field for SO_2 and PM_{10} emissions from the Desert Rock Energy Facility. Therefore, a cumulative analysis was performed for these two pollutants.

The development of the background source inventory was described in Section 6.2.4. The SO_2 sources that were included in the analysis are listed in Table 6-9 and the locations of the sources are shown in Figure 6-6. The PM_{10} sources that were included in the analysis are listed in Table 6-10 and the locations are shown in Figure 6-7.

The receptors included in the cumulative modeling for SO_2 and PM_{10} increment are shown in Figures 6-8 and 6-9, respectively. Receptors were placed within the SIA, which reflected circles of roughly 11 km and 1.7 km, respectively, as discussed above.

The cumulative PSD Class II modeling results are presented in Table 6-11a and the NAAQS results are presented in Table 6-11b. All values are well below the PSD Class II Increments and these results show that the Project will not have a significant impact on SO_2 or PM_{10} air quality.

Table 6-9
Class II SO_2 Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
PSD Increment Consuming Sources										
Conoco, Inc./San Juan Gas Plant	POINT	6	177.7170	81.7762	1710.7	0.007	17.07	690.93	14.23	5.70
Conoco, Inc./San Juan Gas Plant	POINT	7	177.7170	81.7762	1710.7	0.007	13.72	505.37	11.61	1.95
Conoco, Inc./San Juan Gas Plant	POINT	8	177.7170	81.7762	1710.7	0.007	13.72	505.37	11.61	1.95
Conoco, Inc./San Juan Gas Plant	POINT	9	177.6100	82.5624	1706.8	0.001	9.45	672.04	30.48	1.01
Conoco, Inc./San Juan Gas Plant	POINT	10	177.6104	82.5566	1710.7	0.001	9.45	672.04	30.48	1.01
Conoco, Inc./San Juan Gas Plant	POINT	11	177.6107	82.5507	1710.7	0.001	9.45	672.04	30.48	1.01
Conoco, Inc./San Juan Gas Plant	POINT	12	177.6110	82.5449	1710.7	0.001	9.45	672.04	30.48	1.01
Conoco, Inc./San Juan Gas Plant	POINT	13	177.7312	81.6801	1710.7	0.001	9.14	560.93	6.40	0.91
Conoco, Inc./San Juan Gas Plant	POINT	14	177.2912	81.8157	1702.8	0.001	9.14	560.93	6.40	1.10
Conoco, Inc./San Juan Gas Plant	POINT	15	177.2912	81.8157	1702.8	0.701	12.19	533.15	6.40	0.91
Consolidated Constr/Asphalt	POINT	16	153.4319	79.2029	1638.3	4.299	12.80	427.59	19.60	1.04
Consolidated Constr/Crusher	POINT	17	153.2172	79.2239	1636.1	0.159	4.88	730.93	46.63	0.15
Consolidated Constr/Crusher	POINT	18	153.2074	79.2142	1636.6	0.256	3.66	733.15	55.47	0.15
El Paso Field Srvc/Chaco Plant	POINT	19	164.5847	54.2197	1844.0	0.003	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	20	164.5950	54.2291	1844.0	0.003	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	21	164.6052	54.2385	1844.0	0.003	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	22	164.6391	54.3148	1844.0	0.001	8.23	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	23	164.6327	54.3075	1844.0	0.001	22.86	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	24	164.6391	54.3148	1844.0	0.001	8.23	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	25	164.8446	54.1931	1844.2	0.009	15.24	759.26	29.02	2.29
El Paso Field Srvc/Chaco Plant	POINT	26	164.8450	54.1853	1844.2	0.009	15.24	759.26	29.02	2.29
El Paso Field Srvc/Chaco Plant	POINT	27	164.8089	54.2185	1844.2	0.001	6.71	737.59	33.53	0.51
El Paso Field Srvc/Chaco Plant	POINT	28	164.8098	54.2029	1844.2	0.001	6.71	737.59	33.53	0.51

Table 6-9
Class II SO_2 Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
El Paso Field Srvc/Chaco Plant	POINT	29	164.6295	54.1889	1844.2	0.019	12.50	755.37	45.11	2.74
El Paso Field Srvc/Chaco Plant	POINT	30	164.4197	54.4571	1844.2	0.001	6.71	737.59	33.53	0.51
El Paso Field Srvc/Chaco Plant	POINT	31	164.8455	54.1775	1844.2	0.009	15.24	759.26	29.02	2.29
El Paso Field Srvc/Chaco Plant	POINT	32	164.4243	54.4623	1844.2	0.001	6.71	737.59	33.53	0.51
El Paso Field Srvc/Chaco Plant	POINT	33	164.5382	54.2289	1844.2	0.018	5.49	697.04	32.61	0.15
El Paso Field Srvc/Chaco Plant	POINT	34	164.3896	54.8029	1844.2	0.000	2.44	1273.15	19.99	0.21
El Paso Field Srvc/Chaco Plant	POINT	35	164.9330	54.3449	1844.2	0.000	39.62	1273.15	19.99	0.10
El Paso Field Srvc/Chaco Plant	POINT	36	164.9986	54.3270	1844.2	0.805	30.48	727.59	16.06	0.86
El Paso Field Srvc/Chaco Plant	POINT	37	164.6834	54.9753	1844.0	0.000	6.40	922.04	3.63	0.25
El Paso Field Srvc/Chaco Plant	POINT	38	164.6834	54.9753	1844.0	0.000	6.40	922.04	3.63	0.25
El Paso Field Srvc/Chaco Plant	POINT	39	164.6834	54.9753	1844.0	0.000	6.40	922.04	5.09	0.25
El Paso Field Srvc/Chaco Plant	POINT	40	164.6834	54.9753	1844.0	0.000	7.01	922.04	4.42	0.30
El Paso Field Srvc/Chaco Plant	POINT	41	164.6932	54.9752	1844.2	0.000	7.01	922.04	3.63	0.25
El Paso Field Srvc/Chaco Plant	POINT	42	164.7067	54.3497	1845.0	0.003	6.71	713.71	58.83	0.51
El Paso Field Srvc/Chaco Plant	POINT	43	164.7145	54.3418	1845.2	0.003	6.71	713.71	58.83	0.51
El Paso Natural Gas/Blanco CS	POINT	44	177.8317	81.7543	1707.0	0.012	15.24	505.37	30.78	1.93
El Paso Natural Gas/Kutz CS	POINT	45	167.5923	80.2610	1706.0	0.002	6.10	737.59	25.60	0.66
El Paso Natural Gas/Kutz CS	POINT	46	167.5923	80.2610	1706.0	0.002	6.10	737.59	25.60	0.66
Fesco Contr/Crusher/Farmington	POINT	47	162.1229	80.2969	1676.0	0.112	1.83	783.15	114.33	0.30
Fesco Contr/Crusher/Farmington	POINT	48	162.1229	80.2969	1676.0	0.069	3.05	813.71	14.69	0.18
Fesco Contr/Crusher/Aztec	POINT	49	169.8183	92.1606	1767.0	0.164	3.66	733.15	43.59	0.15
Four Corners Materials, Inc./Crusher	POINT	50	153.4214	79.0857	1641.8	0.181	3.05	849.82	83.52	0.20
Four Corners Materials, Inc./Crusher	POINT	51	153.4214	79.0857	1596.3	0.363	3.05	730.93	53.71	0.30
Four Corners Materials, Inc./Crusher	POINT	52	153.4214	79.0857	1641.8	0.727	3.05	752.59	124.54	0.30

Table 6-9
Class II SO_2 Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
Four Corners Materials, Inc./Asphalt	POINT	53	153.5395	79.2217	1638.3	0.009	12.50	416.48	24.44	1.04
Giant Industries/Bloomfield Refinery	POINT	57	176.8653	78.1801	1673.3	0.033	16.76	755.37	2.83	1.13
Giant Industries/Bloomfield Refinery	POINT	58	176.8653	78.1801	1673.3	0.089	9.14	449.82	1.37	0.91
Giant Industries/Bloomfield Refinery	POINT	59	176.8653	78.1801	1673.3	0.143	12.50	494.26	2.19	1.37
Giant Industries/Bloomfield Refinery	POINT	60	176.8653	78.1801	1673.3	5.383	24.38	1273.15	20.12	0.30
Giant Industries/Bloomfield Refinery	POINT	61	176.8653	78.1801	1673.3	0.009	14.02	644.26	6.16	0.55
Giant Industries/Bloomfield Refinery	POINT	62	176.8653	78.1801	1673.3	0.012	12.19	616.48	8.50	0.55
Giant Industries/Bloomfield Refinery	POINT	63	176.8653	78.1801	1673.3	0.001	12.19	598.15	5.49	0.76
NavajoRefining/BulkProduct Terminal	POINT	64	177.7128	75.2930	1750.6	0.037	7.62	1033.15	1.04	0.30
Public Service Co NM/San Juan GS	POINT	67	136.0993	88.1943	1614.9	168.170	121.92	322.04	15.85	8.53
Public Service Co NM/San Juan GS	POINT	68	136.0993	88.1943	1614.9	182.341	121.92	322.04	15.85	8.53
Transwestern Pipeline/Bloomfield CS	POINT	69	179.0205	81.2461	1704.3	0.012	15.24	755.37	46.45	1.07
Transwestern Pipeline/Bloomfield CS	POINT	70	179.0199	81.2559	1704.0	0.012	15.24	755.37	46.45	1.07
Transwestern Pipeline/Bloomfield CS	POINT	71	179.0194	81.2657	1710.7	0.012	15.24	755.37	46.45	1.07
Valley Scrap Metal/Alum Sweat Furn	POINT	72	144.8035	81.5583	1590.7	0.202	3.96	1144.26	3.17	0.46

Table 6-9
Class II SO_2 Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
Additional Sources for NAAQS Modeling										
Arizona Public Serv/4 Corners/GF	POINT	1	132.5486	76.2073	1615.0	95.158	76.20	327.59	18.29	5.36
Arizona Public Serv/4 Corners/GF	POINT	2	132.5486	76.2073	1615.0	93.374	76.20	327.59	18.29	5.36
Arizona Public Serv/4 Corners/GF	POINT	3	132.6197	76.1436	1615.0	110.059	76.20	327.59	31.63	4.36
Arizona Public Serv/4 Corners/GF	POINT	4	132.9928	75.8145	1615.0	227.971	115.82	333.15	23.89	8.69
Arizona Public Serv/4 Corners/GF	POINT	5	132.9928	75.8145	1615.0	273.392	115.82	333.15	18.29	8.69
Giant Industries/Bloomfield Ref/402M8	POINT	54	176.8653	78.1801	1673.3	10.685	42.06	538.71	9.14	0.91
Giant Industries/Bloomfield Ref/402M8	POINT	55	176.8555	78.1796	1673.3	7.284	27.43	583.15	0.98	2.01
Giant Industries/Bloomfield Ref/402M8	POINT	56	176.8653	78.1801	1673.3	2.624	23.77	766.48	4.94	1.10
Public Service Co NM/San Juan GS	POINT	65	136.0993	88.1943	1614.9	202.938	121.92	319.82	18.90	6.10
Public Service Co NM/San Juan GS	POINT	66	136.0993	88.1943	1614.9	201.635	121.92	317.59	18.29	6.10
Public Service Co NM/San Juan GS	POINT	74	136.0993	88.1943	1614.9	2.250	6.00	293.00	1.50	1.00
Western Gas Resources/San Juan	POINT	73	142.4155	83.6558	1614.8	89.951	62.79	810.93	3.41	0.91

Figure 6-6 Cumulative Modeling SO_2 Source Locations

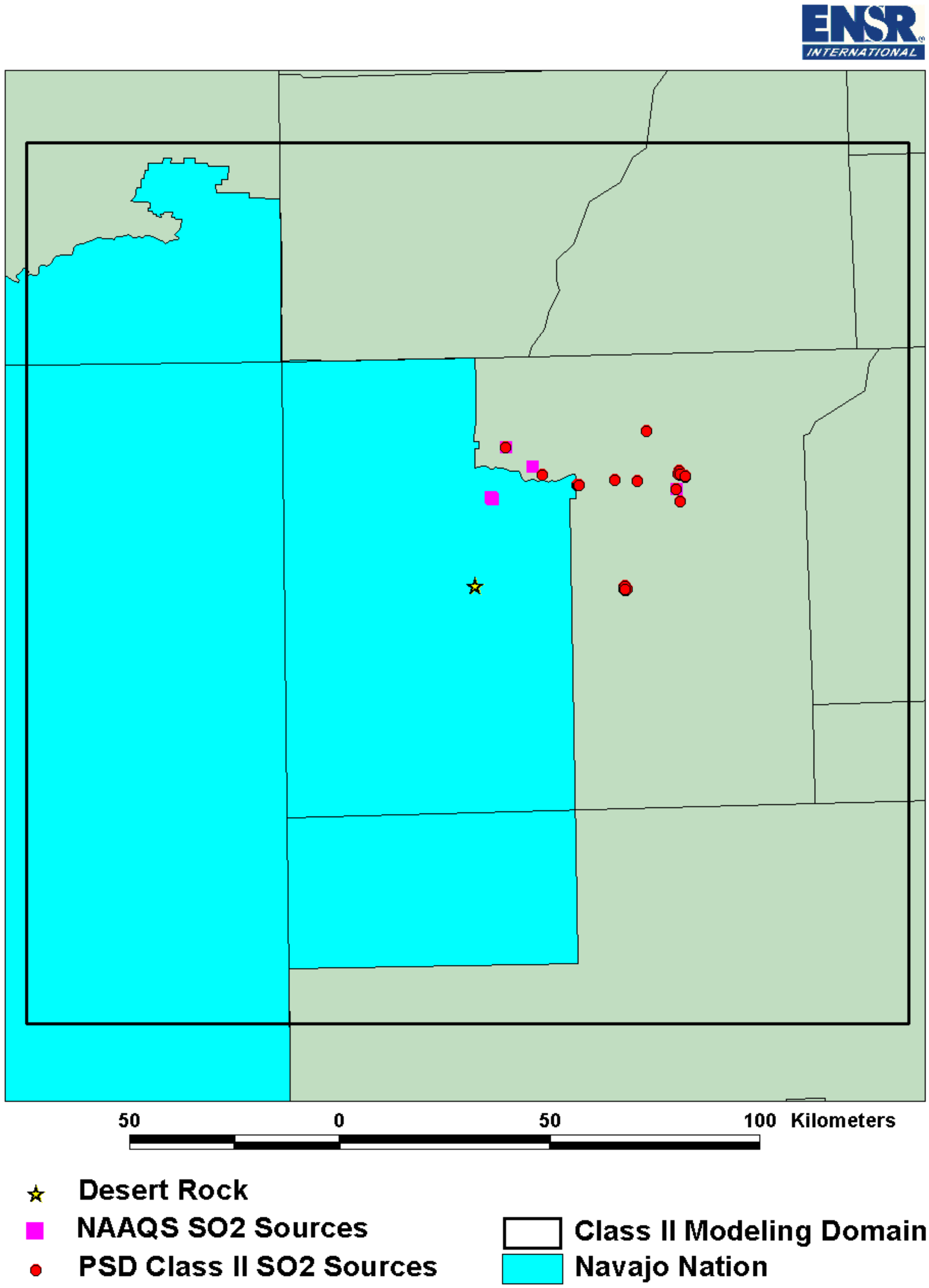

Figure 6-7 Cumulative Modeling PM_{10} Source Locations

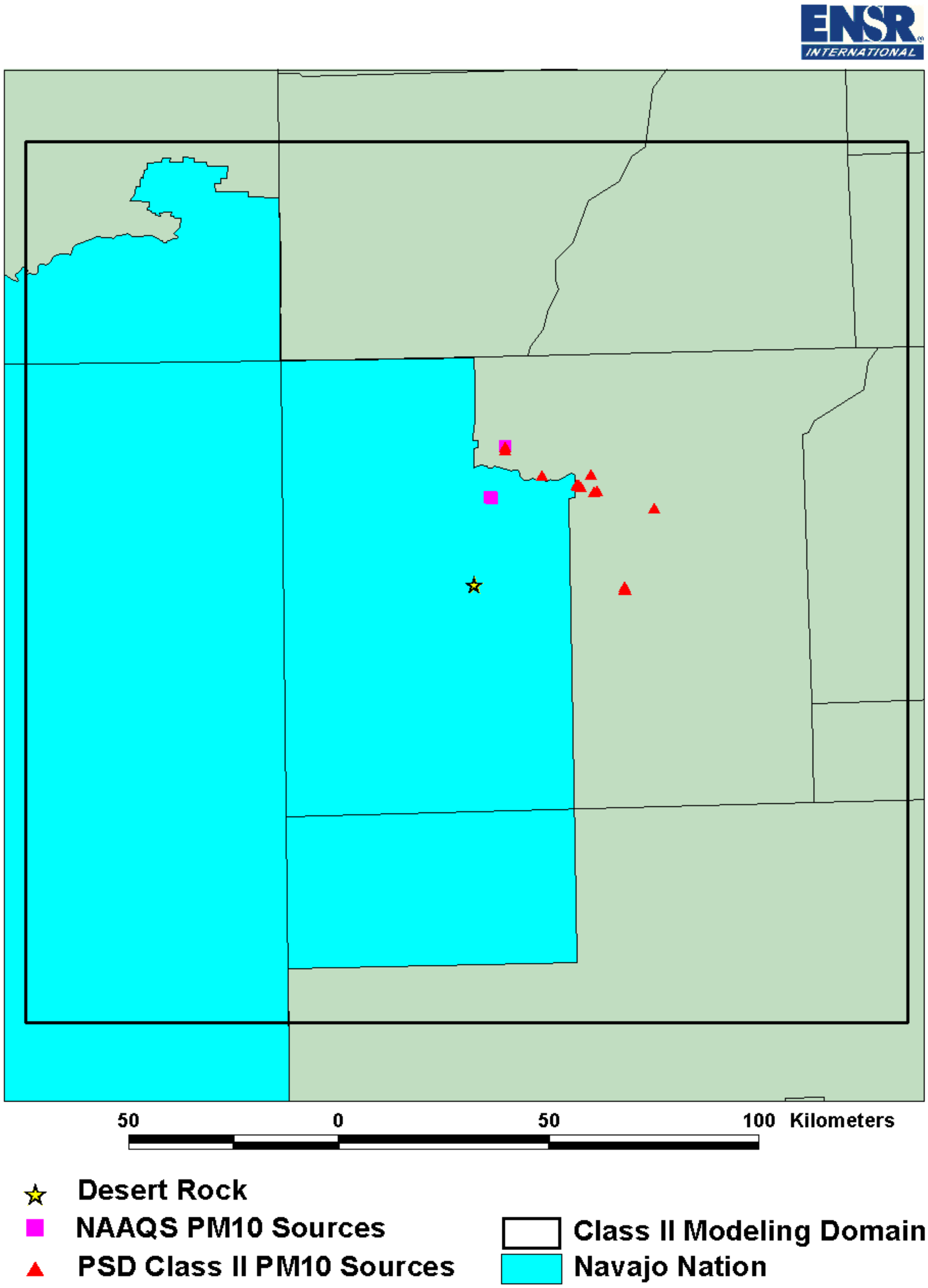

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Table 6-10
Class II PM_{10} Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	PM10 ER (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
PSD Increment Consuming Sources										
Bloomfield Gravel/300tph Crusher	POINT	6	171.6524	73.6905	1722.3	0.170	6.00	293.00	1.50	1.00
Consolidated Constr/Asphalt	POINT	7	153.4319	79.2029	1638.3	0.284	12.80	427.59	19.60	1.04
Consolidated Constr/Crusher	POINT	8	153.2465	79.2237	1636.2	0.443	7.60	697.00	32.60	0.30
El Paso Field Srvc/Chaco Plant	POINT	9	164.5847	54.2197	1844.0	0.152	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	10	164.5950	54.2291	1844.0	0.152	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	11	164.6052	54.2385	1844.0	0.152	10.67	612.59	39.32	0.74
El Paso Field Srvc/Chaco Plant	POINT	12	164.6391	54.3148	1844.0	0.081	8.23	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	13	164.6327	54.3075	1844.0	0.081	22.86	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	14	164.6391	54.3148	1844.0	0.081	8.23	595.37	40.23	0.44
El Paso Field Srvc/Chaco Plant	POINT	15	164.8446	54.1931	1844.2	0.029	15.24	759.26	29.02	2.29
El Paso Field Srvc/Chaco Plant	POINT	16	164.8450	54.1853	1844.2	0.029	15.24	759.26	29.02	2.29
El Paso Field Srvc/Chaco Plant	POINT	17	164.8089	54.2185	1844.2	0.032	6.71	737.59	33.53	0.51
El Paso Field Srvc/Chaco Plant	POINT	18	164.8098	54.2029	1844.2	0.032	6.71	737.59	33.53	0.51
El Paso Field Srvc/Chaco Plant	POINT	19	164.6295	54.1889	1844.2	0.046	12.50	755.37	45.11	2.74
El Paso Field Srvc/Chaco Plant	POINT	20	164.6834	54.9753	1844.0	0.026	6.40	922.04	3.63	0.25
El Paso Field Srvc/Chaco Plant	POINT	21	164.6834	54.9753	1844.0	0.026	6.40	922.04	3.63	0.25
El Paso Field Srvc/Chaco Plant	POINT	22	164.6834	54.9753	1844.0	0.032	6.40	922.04	5.09	0.25
El Paso Field Srvc/Chaco Plant	POINT	23	164.6834	54.9753	1844.0	0.032	7.01	922.04	4.42	0.30
El Paso Field Srvc/Chaco Plant	POINT	24	164.7067	54.3497	1845.0	0.063	6.71	713.71	58.83	0.51
El Paso Field Srvc/Chaco Plant	POINT	25	164.7145	54.3418	1845.2	0.063	6.71	713.71	58.83	0.51
Four Corners Materials, Inc./Crusher	POINT	26	153.4214	79.0857	1641.8	1.864	6.00	293.00	1.50	1.00
Four Corners Materials, Inc./Asphalt	POINT	27	153.5395	79.2217	1638.3	0.372	12.50	416.48	24.44	1.04
Four Corners Materials, Inc./Batch	POINT	28	156.5655	81.7993	1644.6	1.092	7.60	697.00	32.60	0.30
Halliburton/Cement & Sand/425M2	POINT	29	154.1025	78.6903	1645.0	0.005	10.67	302.59	0.43	0.66
Halliburton/Cement & Sand/425M2	POINT	30	154.1025	78.6903	1645.0	0.269	7.92	302.59	14.90	0.76
Industrial Repair Service/Elecro-mec	POINT	31	158.0030	77.6871	1645.9	0.618	6.00	293.00	1.50	1.00
Phoenix Cement/San Juan Fly Ash	POINT	32	136.1927	87.6075	1645.9	0.073	32.61	330.37	20.70	0.76
Phoenix Cement/San Juan Fly Ash	POINT	33	136.1927	87.6075	1645.9	0.053	25.60	297.04	21.00	0.61
Phoenix Cement/San Juan Fly Ash	POINT	34	136.1927	87.6075	1645.9	0.018	36.27	273.00	0.00	1.00

Table 6-10
Class II PM_{10} Inventory

Facility	Release Type	MODEL ID	LAM-X (km)	LAM-Y (km)	Elevation (m)	PM10 ER (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
Phoenix Cement/San Juan Fly Ash	POINT	35	136.1927	87.6075	1645.9	0.029	38.71	330.37	21.37	0.34
Public Service Co NM/San Juan GS	POINT	38	136.0993	88.1943	1614.9	34.220	121.92	322.04	15.85	8.53
Public Service Co NM/San Juan GS	POINT	39	136.0993	88.1943	1614.9	33.573	121.92	322.04	15.85	8.53
Public Service Co NM/San Juan GS	POINT	41	136.0993	88.1943	1614.9	0.489	6.00	293.00	1.50	1.00
Public Service Co NM/San Juan GS	POINT	42	136.0993	88.1943	1614.9	0.127	7.60	697.00	32.60	0.30
Valley Scrap Metal/Alum Sweat	POINT	43	144.8035	81.5583	1590.7	0.832	3.96	1144.26	3.17	0.46
Western Tank Mfg/Farmington Plant	POINT	44	157.4162	77.5934	1644.8	0.545	7.60	697.00	32.60	0.30
Additional Sources for NAAQS Modeling										
Arizona Public Serv/4 Corners/GF	POINT	1	132.5486	76.2073	1615.0	36.872	76.20	327.59	18.29	5.36
Arizona Public Serv/4 Corners/GF	POINT	2	132.5486	76.2073	1615.0	34.155	76.20	327.59	18.29	5.36
Arizona Public Serv/4 Corners/GF	POINT	3	132.6197	76.1436	1615.0	46.373	76.20	327.59	31.63	4.36
Arizona Public Serv/4 Corners/GF	POINT	4	132.9928	75.8145	1615.0	40.338	115.82	333.15	23.89	8.69
Arizona Public Serv/4 Corners/GF	POINT	5	132.9928	75.8145	1615.0	40.336	115.82	333.15	18.29	8.69
Public Service Co NM/San Juan GS	POINT	36	136.0993	88.1943	1614.9	22.029	121.92	319.82	18.90	6.10
Public Service Co NM/San Juan GS	POINT	37	136.0993	88.1943	1614.9	21.917	121.92	317.59	18.29	6.10
Public Service Co NM/San Juan GS	POINT	40	136.0993	88.1943	1614.9	32.907	6.00	293.00	1.50	1.00

Figure 6-8 Receptors for Cumulative SO_2 Modeling

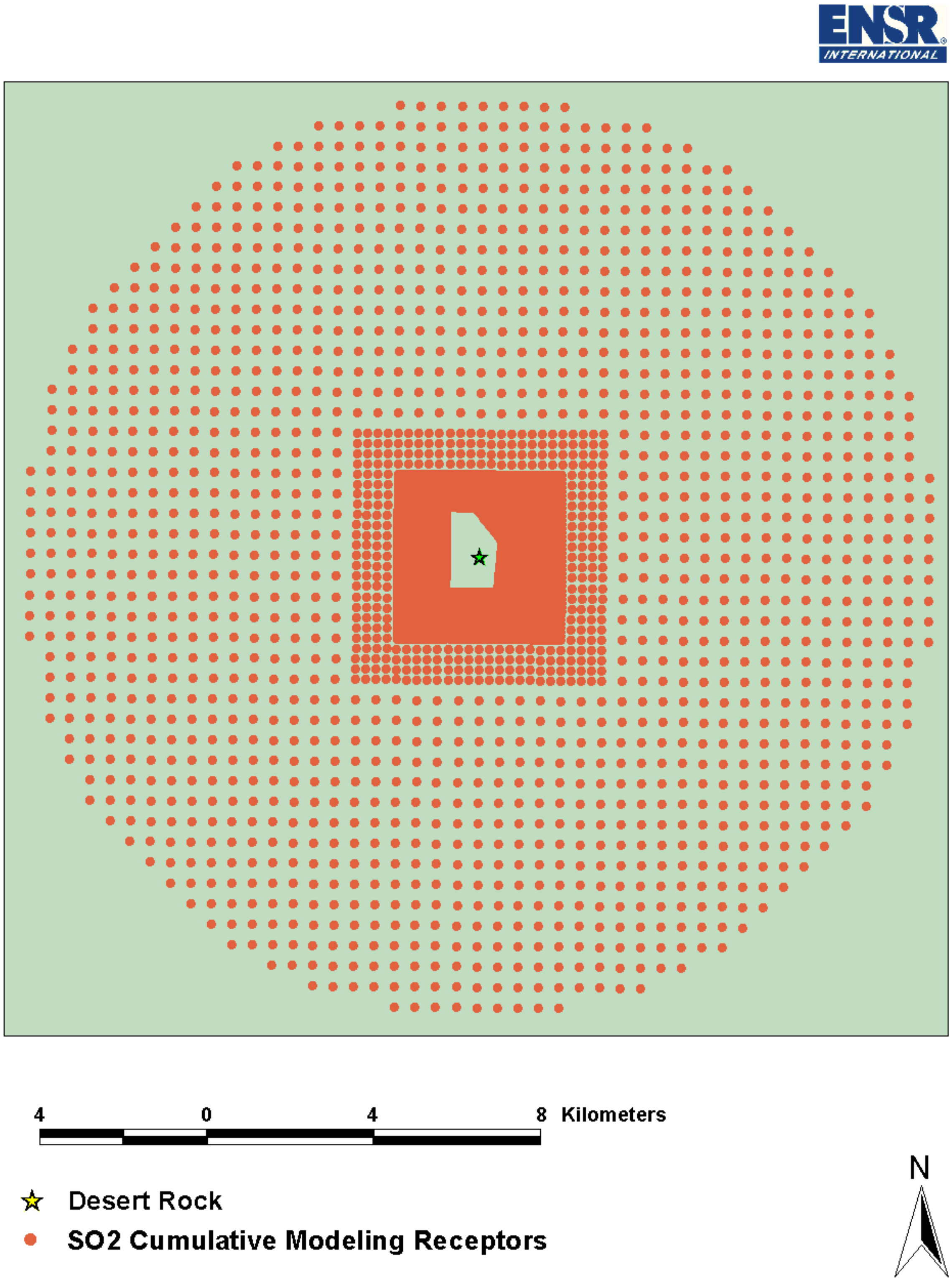

Figure 6-9 Receptors for Cumulative PM_{10} Modeling

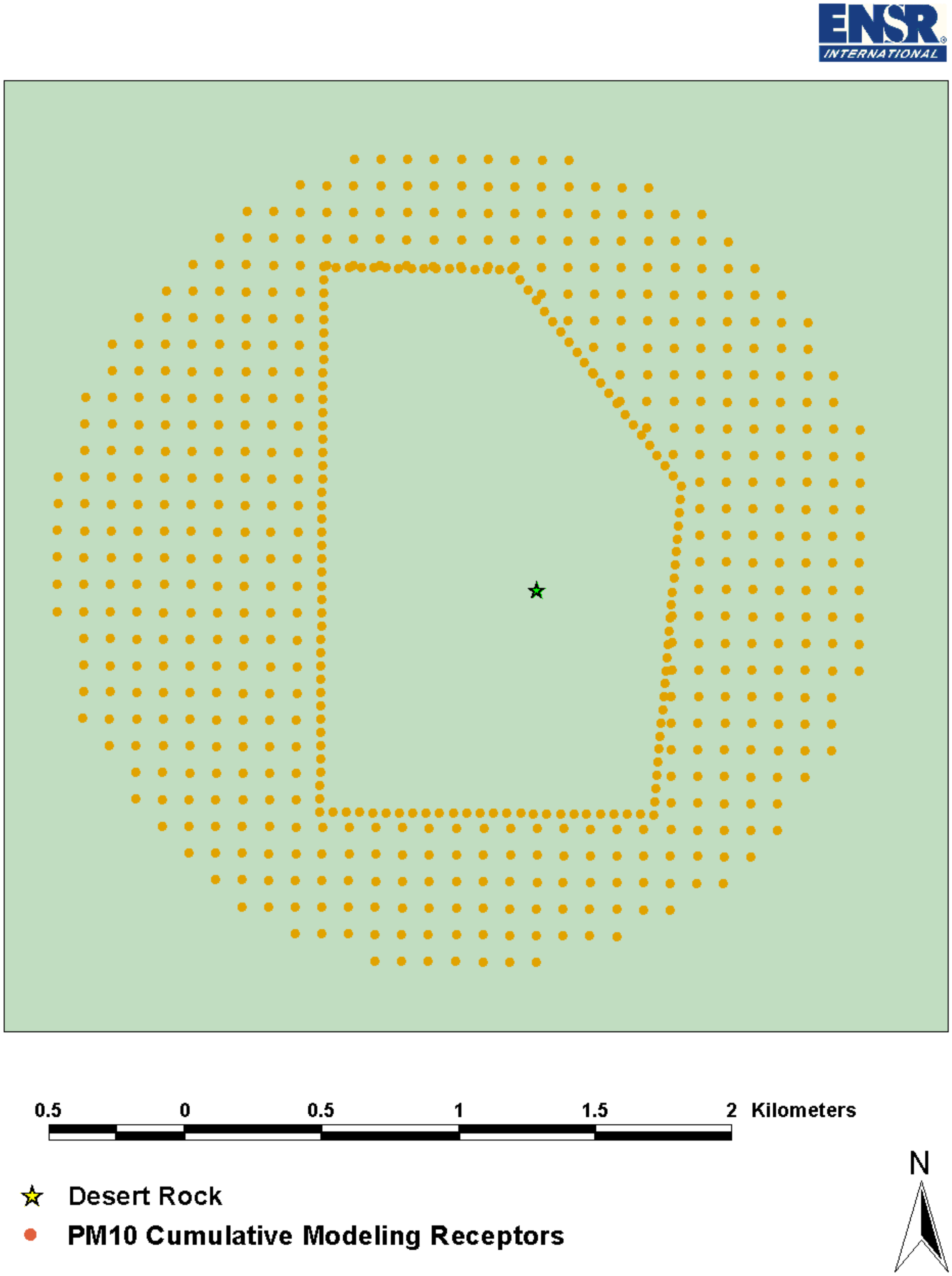

Table 6-11a
Cumulative PSD Class II Modeling Results

Pollutant	Averaging Period	Modeled Concentration (µg/m^3) [1]	Distance (km)	Bearing (Deg.)	PSD Class II Increment (µg/m^3)	% of Increment
SO_2	3 Hour [2]	95.20	1.2	275	512	19%
	24 Hour	11.24	1.3	270	91	12%
PM_{10}	24 Hour	8.58	0.7	56	30	29%
	Annual	2.10	0.5	19	17	12%

1. Second-highest short-term values, highest annual values.
2. SO_2 3-hour results are based on an emission rate of 0.09 lb/MMBtu to account for short-term variability. Emissions levels could be much greater and still not cause an increment exceedance.

Table 6-11b
Cumulative NAAQS Modeling Results

Pollutant	Averaging Period	Modeled Concentration (µg/m^3)[(1)]	Regional Background (µg/m^3)	Total Conc. (µg/m^3)	Distance (km)	Bearing (Deg.)	NAAQS (µg/m^3)	% of Ambient Standard
SO_2	3 Hour [1]	133.87	68.1	201.97	10.9	63	1300	16%
	24 Hour	33.42	21.0	54.42	11.0	69	365	15%
PM_{10}	24 Hour	10.67	38.0	48.67	0.7	56	150	32%
	Annual	2.57	17.0	19.57	0.7	56	50	39%

1. SO_2 3-hour results are based on an emission rate of 0.09 lb/MMBtu to account for short-term variability. Emissions levels could be much greater and still not cause a NAAQS exceedance.

6.4 Distant Class II Area Assessment

CALPUFF was used to assess impacts at distant sensitive Class II areas (beyond 50 kilometers) as requested by the Federal Land Managers (FLMs). These areas are shown in Figure 6-10, and include:

- Aztec Ruins National Monument
- Canyon de Chelly National Monument
- Chaco Culture National Historic Park
- Colorado National Monument
- Cruces Basin Wilderness Area
- Curecanti National Recreation Area
- El Malpais National Monument
- El Morro National Monument
- Glen Canyon National Recreation Area
- Hovenweep National Monument
- Hubbel Trading Post National Historic Site
- Lizard Head Wilderness Area
- Mount Sneffels Wilderness Area
- Natural Bridges National Monument
- Navajo National Monument
- Pecos National Historic Park
- Petroglyph National Monument
- Rainbow Bridge National Monument
- Salinas Pueblo Missions National Monument
- South San Juan Wilderness Area
- Sunset Crater National Monument
- Wupatki National Monument
- Yucca House National Monument
- Zuni-Cibola NHP
- Wilson Mountain Primitive Area
- Uncompahgre Wilderness Area

Except where noted below, impacts at these areas have been addressed in terms of PSD Class II increment, regional haze, and acidic deposition. For all pollutants and averaging periods at each distant PSD Class II area, the modeling results discussed below show the project to have an insignificant modeled increment, so no further modeling is required (Class II significance thresholds are shown in Table 6-6). Since these areas are not Class I designated, regional haze and acidic deposition results associated with emissions from the main stacks alone are not subject to the FLAG Phase I (2000) procedures. Therefore, the results are being reported for informational purposes and are not compared to thresholds that are applicable for a Class I area.

Colorado National Monument, Wilson Mountain Primitive Area, and Uncompahgre Wilderness Area are Class I protected areas for SO_2 PSD increment in Colorado. Therefore, the SO_2 Class I significance thresholds and increments apply to these Class II areas only. Proposed Class I significance thresholds and increment values can also be found in Table 6-6.

This modeling analysis assessed the impacts at the specified Class II areas from the proposed project's main stack alone operating at 100 percent load. Other small ancillary or fugitive sources were not included in this portion of the modeling analysis because the effects of these sources are expected to be confined within the first few hundred meters of the project site.

Figure 6-10 Distant Sensitive PSD Class II Areas Considered in the Modeling Analysis

Receptor grids for these areas were generated based on the suggestions of John Notar of the NPS. Receptor elevations were either picked from a topographic map or calculated using 90-meter spaced Digital Elevation Model (DEM) files.

The identified distant PSD Class II areas noted by the Federal Land Managers are all beyond 50 km from the proposed source. Results of the PSD Class II increment modeling for these distant areas are provided in Table 6-12. For these Class II areas, there are no impacts above the Class II SILs. The three areas in Colorado where PSD Class I SO_2 increments apply are noted in the table, and the concentrations are above the Class I SILs in these three areas (bolded in yellow).

Table 6-12
Highest Modeled PSD Increment Concentrations ($\mu g/m^3$)
Over Three Years (2001-2003), Distant Class II Areas

Pollutant	NO_X	SO_2			PM_{10}	
Averaging Period	Annual	3-hour	24-hour	Annual	24-hour	Annual
Aztec Ruins Nat. Mon.	0.010	2.144	0.339	0.032	0.313	0.026
Canyon de Chelly Nat. Mon.	0.005	1.984	0.277	0.016	0.313	0.016
Chaco Culture NHP	0.018	2.369	0.456	0.045	0.330	0.035
Colorado Nat. Mon.*	0.002	1.172	0.150	0.005	0.141	0.006
Cruces Basin NWA	0.007	1.231	0.203	0.016	0.145	0.014
Curecanti NRA	0.002	1.636	0.273	0.005	0.184	0.006
El Malpais Nat. Mon.	0.005	1.503	0.195	0.010	0.282	0.010
El Morro Nat. Mon.	0.002	0.912	0.156	0.007	0.212	0.007
Glen Canyon NRA	0.003	1.187	0.274	0.011	0.339	0.012
Hovenweep Nat. Mon.	0.003	1.852	0.223	0.016	0.167	0.015
Hubbel Trading Post NHS	0.001	1.128	0.179	0.006	0.237	0.007
Lizard Head NWA	0.003	1.260	0.294	0.008	0.158	0.008
Mount Sneffels NWA	0.003	0.966	0.201	0.007	0.168	0.007
Natural Bridges Nat. Mon.	0.003	1.092	0.205	0.009	0.216	0.009
Navajo Nat. Mon.	0.001	0.779	0.109	0.004	0.156	0.005
Pecos NHP	0.004	0.979	0.161	0.009	0.123	0.012
Petroglyph Nat. Mon.	0.007	0.715	0.254	0.018	0.225	0.015
Rainbow Bridge Nat. Mon.	0.000	0.433	0.065	0.003	0.135	0.005
Salinas Pueblo Missions Nat. Mon.	0.003	0.566	0.117	0.008	0.142	0.009
South San Juan NWA	0.010	1.637	0.291	0.019	0.192	0.016
Sunset Crater Nat. Mon.	0.000	0.358	0.046	0.001	0.087	0.002
Uncompahgre NWA*	0.004	1.258	0.279	0.009	0.176	0.008
Wilson Mountain Primitive Area*	0.002	1.106	0.186	0.007	0.149	0.007
Wupatki Nat. Mon.	0.000	0.191	0.039	0.001	0.104	0.003
Yucca House Nat. Mon.	0.003	1.923	0.250	0.012	0.240	0.012
Zuni-Cibola NHP	0.002	0.761	0.132	0.007	0.202	0.008
* subject under Colorado regulation to Class I SO_2 increment protection						

Since the three Class II areas in Colorado are over the Class I increments, they were included in the SO_2 cumulative analysis that was performed for the Class I areas as described in Section 6.5.3. The SO_2 results (high-second high in μg/m³) of the cumulative analysis for these three areas are:

	3-hour	24-hour
• Colorado National Monument	6.27	1.23
• Uncompahgre NWA	8.79	1.94
• Wilson Mountain Primitive Area	5.34	1.75

These values are well below the PSD Class I increments of 25 μg/m³ 3-hour and 5 μg/m³ 24-hour that are applied by the State of Colorado for these Class II areas.

For informational purposes, results of the visibility (regional haze) assessment for these areas are provided in Table 6-13 and of the sulfur and nitrogen deposition modeling are provided in Table 6-14.

Table 6-13
CALPUFF PSD Class II Regional Haze Impact Analysis (Highest Extinction Over Three Years), Distant PSD Class II Areas

Class II Area	Max Percent (%) Extinction Change	
	FLAG f(RH) Values	EPA f(RH) Values, Includes Salt Aerosol
Aztec Ruins Nat. Mon.	6.16	5.18
Canyon de Chelly Nat. Mon.	6.64	6.67
Chaco Culture NHP	11.24	10.09
Colorado Nat. Mon.	2.82	2.93
Cruces Basin NWA	6.21	5.98
Curecanti NRA	6.17	6.68
El Malpais Nat. Mon.	7.26	7.78
El Morro Nat. Mon.	4.80	4.48
Glen Canyon NRA	7.23	6.99
Hovenweep Nat. Mon.	7.74	6.74
Hubbel Trading Post NHS	6.18	6.34
Lizard Head NWA	5.04	5.34
Mount Sneffels NWA	3.70	4.14
Natural Bridges Nat. Mon.	4.16	3.95
Navajo Nat. Mon.	3.91	3.64
Pecos NHP	4.92	4.43
Petroglyph Nat. Mon.	4.26	4.40
Rainbow Bridge Nat. Mon.	3.57	3.90
Salinas Pueblo Missions Nat. Mon.	3.37	3.70
South San Juan NWA	7.02	5.94
Sunset Crater Nat. Mon.	2.92	2.55
Uncompahgre NWA	6.39	6.65
Wilson Mountain Primitive Area	3.54	3.88
Wupatki Nat. Mon.	3.25	3.01
Yucca House Nat. Mon.	8.97	7.91
Zuni-Cibola NHP	5.40	5.77
MVISBK=2, RHMAX=95%, 10% ranked lowest background extinction		

Results the second column of Table 6-13 employ the FLAG f(RH) curve, while the values in the third column employ the recently published EPA updates to the f(RH) curve. The EPA version of the f(RH) curve generally results in lower predicted changes to regional haze impacts. The 10% ranked lowest background extinction values are obtained from data provided prior to FLAG implementation by John Notar of the NPS. No attempt has been made to refine these results by reviewing periods of natural obscuration due to meteorological interferences. Steag provides this information to show that the proposed project will not have an adverse impact on distant PSD Class II areas.

Table 6-14
Maximum Total Deposition Over Three Years (2001-2003), Distant PSD Class II Areas

PSD Class II Area	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Aztec Ruins Nat. Mon.	1.00E-02	3.08E-02
Canyon de Chelly Nat. Mon.	5.61E-03	1.45E-02
Chaco Culture NHP	1.29E-02	2.99E-02
Colorado Nat. Mon.	2.15E-03	4.76E-03
Cruces Basin NWA	5.74E-03	1.20E-02
Curecanti NRA	2.44E-03	4.86E-03
El Malpais Nat. Mon.	3.44E-03	7.82E-03
El Morro Nat. Mon.	2.52E-03	5.46E-03
Glen Canyon NRA	3.19E-03	7.98E-03
Hovenweep Nat. Mon.	5.49E-03	1.17E-02
Hubbel Trading Post NHS	3.09E-03	6.59E-03
Lizard Head NWA	3.78E-03	8.83E-03
Mount Sneffels NWA	3.28E-03	7.32E-03
Natural Bridges Nat. Mon.	3.12E-03	8.20E-03
Navajo Nat. Mon.	1.29E-03	3.07E-03
Pecos NHP	3.66E-03	8.45E-03
Petroglyph Nat. Mon.	4.29E-03	1.02E-02
Rainbow Bridge Nat. Mon.	1.33E-03	2.95E-03
Salinas Pueblo Missions Nat. Mon.	2.24E-03	5.05E-03
South San Juan NWA	7.54E-03	1.48E-02
Sunset Crater Nat. Mon.	7.63E-04	1.37E-03
Uncompahgre NWA	3.78E-03	7.41E-03
Wilson Mountain Primitive Area	3.50E-03	8.14E-03
Wupatki Nat. Mon.	9.18E-04	1.67E-03
Yucca House Nat. Mon.	5.46E-03	1.42E-02
Zuni-Cibola NHP	3.01E-03	6.37E-03

6.5 PSD Class I Modeling Analysis

The impacts at PSD Class I areas within 300 kilometers of the proposed plant (see Figure 6-11) were modeled with CALPUFF. The PSD Class I areas included the following National Parks (NP) or National Monuments (NM):

- Arches
- Bandelier
- Black Canyon of the Gunnison
- Capitol Reef
- Canyonlands
- Grand Canyon
- Great Sand Dunes
- Mesa Verde
- Petrified Forest

PSD Class I areas also included the following Wilderness Areas (WA), all administered by the USDA Forest Service.

- La Garita
- Pecos
- San Pedro Parks
- West Elk
- Weminuche
- Wheeler Peak

The long-range CALPUFF modeling analysis addressed ambient air impacts on Class I PSD Increments and Air Quality Related Values (AQRVs) at these Class I areas.

6.5.1 Modeling Domain and Receptors

The CALPUFF modeling grid system was designed to extend approximately 50 kilometers east of Great Sand Dunes National Park, north of West Elk Wilderness, south of Petrified Forest, as well as 350 kilometers west of the project site. The modeling domain proposed for this analysis is shown in Figure 6-12. The additional buffer distances beyond the Class I areas allow for the consideration of puff trajectory recirculations. This design allows for a 680 km x 552 km (E-W / N-S) grid with a 4-km grid element size. The southwest corner of the grid is located at approximately 34.28° N latitude and 112.46° W longitude.

The receptors used in the refined CALPUFF analysis were limited to those actually within the PSD Class I boundary. However, if the park boundary extended more than 300 kilometers from the project site, then only those receptors within 300 kilometers were modeled in this CALPUFF analysis. The receptors for Arches, Bandelier, Black Canyon of the Gunnison, Capitol Reef, Canyonlands, Grand Canyon, Great Sand Dunes, Mesa Verde, and Petrified Forest National Parks, along with La Garita, Pecos, San Pedro Parks, West Elk, Weminuche, and Wheeler Peak Wilderness Areas were obtained from a database of receptors for all Class I areas produced by the National Park Service.

6.5.2 Project Only PSD Class I Increment Modeling Results

Results of the PSD Class I increment modeling from proposed source emissions are provided in Table 6-15. Values bolded in yellow are greater than the Class I significance levels. The NO_x and PM_{10} impacts are insignificant in all PSD Class I areas, and only the SO_2 impacts are significant. Note that the highest SO_2 impacts are only about 20% of the full PSD Class I increment.

Figure 6-11 PSD Class I Areas Considered in the Modeling Analysis

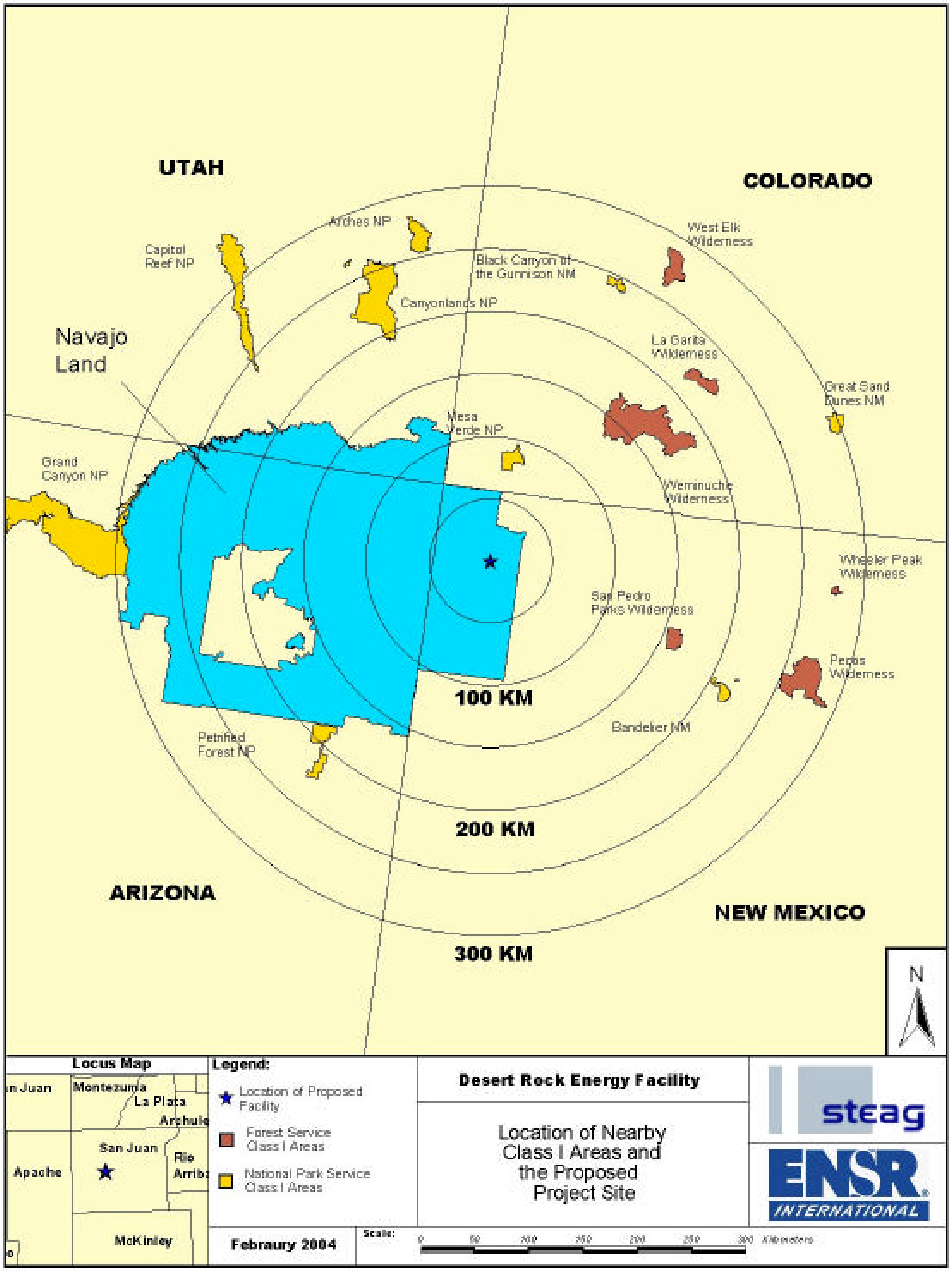

Figure 6-12 PSD Class I CALPUFF Modeling Domain

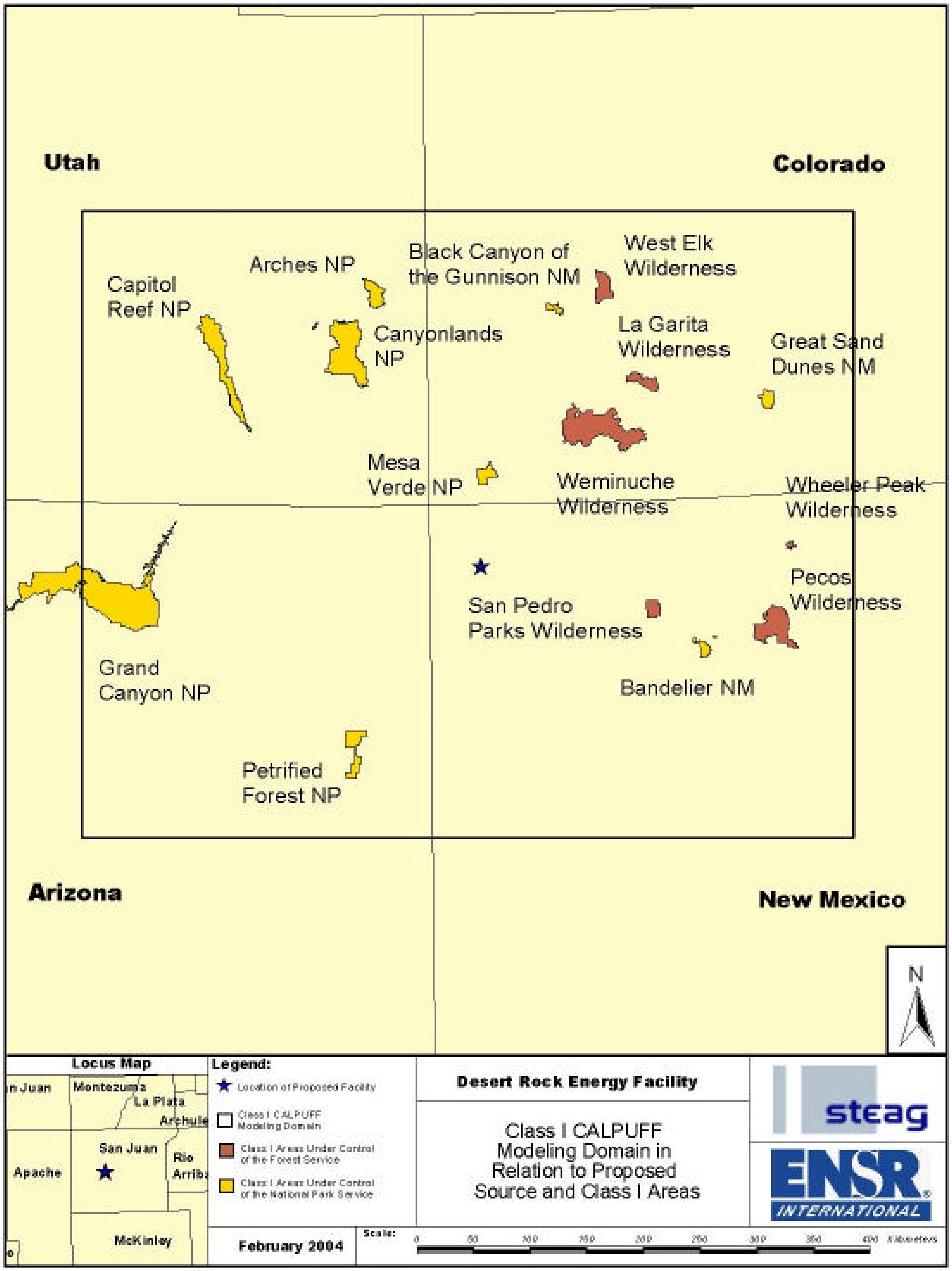

Table 6-15
Highest Modeled PSD Class I Increment Concentrations ($\mu g/m^3$) Over Three Years (2001-2003)

Pollutant	NO_X	SO_2			PM_{10}	
Averaging Period	**Annual**	**3-hour**	**24-hour**	**Annual**	**24-hour**	**Annual**
Arches NP	0.001	1.415	0.172	0.004	0.260	0.005
Bandelier NM	0.008	1.995	0.246	0.018	0.203	0.018
Black Canyon of the Gunnison NM	0.002	1.050	0.177	0.005	0.185	0.006
Canyonlands NP	0.002	0.967	0.202	0.007	0.264	0.007
Capitol Reef NP	0.001	1.120	0.151	0.004	0.219	0.005
Grand Canyon NP	0.000	0.564	0.132	0.002	0.167	0.003
Great Sand Dunes NM	0.005	1.341	0.264	0.013	0.196	0.012
La Garita WA	0.006	1.047	0.205	0.012	0.179	0.010
Mesa Verde NP	0.009	2.662	0.415	0.019	0.293	0.015
Pecos WA	0.006	1.382	0.223	0.014	0.163	0.014
Petrified Forest NP	0.000	0.499	0.102	0.003	0.207	0.005
San Pedro Parks WA	0.011	1.675	0.247	0.025	0.285	0.024
Weminuche WA	0.009	2.031	0.338	0.016	0.207	0.013
West Elk WA	0.002	0.858	0.145	0.004	0.187	0.005
Wheeler Peak WA	0.003	1.174	0.156	0.009	0.118	0.010
Proposed Class I SIL	0.1	1.0	0.2	0.1	0.3	0.2
PSD Class I Increments	2.5	25.0	5.0	2.0	8.0	4.0

6.5.3 Cumulative Class I Increment Modeling Results

A cumulative SO_2 increment modeling analysis was performed since the project-only impacts were greater that the proposed Class I area SILs provided in Table 6-6. The background source inventory is listed in Table 6-16 and the locations of these sources that were included are shown in Figure 6-13.

Two coal-fired power plants, the San Juan Generating Station (SJGS) and the Four Corners Power Plant (FCPP), had emission units that were either operating or under construction as of the SO_2 major source baseline date of January 6, 1975. These units include all five of the FCPP boilers and units 1 and 2 of the SJGS. The determination of the baseline versus current emission differences for these units is discussed in Attachment 6.

The cumulative modeling results for Class I increment are presented in Tables 6-17a and 6-17b. The results in Table 6-17a include increment expansion from FCPP. The results in Table 6-17b include increment expansion from SJGS and FCPP. Both tables show that cumulative impacts will be well below the PSD Class I increments.

Table 6-16
PSD Class I SO_2 Inventory

Name	Model ID	LAM-X (km)	LAM-Y (km)	Base El. (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)
PSD Increment Consuming									
Cholla Unit 2	Cholla2	-26.911	-116.171	1529.0	40.865	167.64	348.71	34.14	4.48
Springerville GS	SGS1-4	75.443	-182.937	2128.0	1064.432	152.40	339.00	21.30	6.10
Abitibi Consolidated	Abitibi2	-30.183	-162.803	1844.0	43.650	65.23	380.37	18.35	3.66
AE Staley MFG	Staley	336.234	179.921	2322.6	2.451	5.18	1273.00	20.80	0.10
Nixon Unit 1	Nixon1	448.075	299.985	1676.4	257.594	140.21	422.59	19.62	5.33
Nixon Unit 2	Nixon2	448.075	299.985	1676.4	6.149	64.01	558.15	15.43	1.07
Kinder Morgan	KMYJ	104.599	160.363	2017.8	1.008	6.10	644.26	2.54	0.61
Cameo Station	CameoCur	141.295	342.308	1463.0	50.652	45.72	399.81	7.77	2.67
Nucla Station	Nucla	127.237	243.666	1694.7	135.274	65.53	408.15	23.34	3.66
Holcim-Florence	HFlor1	423.533	271.358	1536.2	109.000	110.00	376.00	14.52	6.00
Holcim-Florence	HFlor2	423.515	271.386	1536.2	44.900	110.00	356.00	13.99	1.70
Hunter Unit 2	Hunter2	-86.075	343.842	1723.6	65.179	182.88	329.26	17.82	7.32
Hunter Unit 3	Hunter3	-86.096	343.811	1723.6	33.438	182.88	322.04	16.63	7.32
Lisbon Flare	LisFlare	61.757	234.675	1828.8	1.155	12.20	613.15	83.58	0.46
Lisbon Incinerator	LisIncin	62.106	233.890	1828.8	38.800	64.98	736.76	7.35	1.83
Consolidated Constr.	CAsphlt	153.4319	79.2029	1638.3	4.299	12.80	427.59	19.60	1.036
San Juan GS Unit 3	SJGS3	136.0993	88.1943	1614.9	110.907	121.92	322.04	15.85	8.534
San Juan GS Unit 4	SJGS4	136.0993	88.1943	1614.9	120.254	121.92	322.04	15.85	8.534
Bloomfield Refinery	BlmfdRef	176.8653	78.1801	1673.3	5.383	24.38	1273.15	20.12	0.305
Peabody Mustang	Mustang	185.77	-35.03	2112.3	43.474	147.28	343.09	18.29	5.505
Tri-State Escalante	Escalant	170.81	-61.64	2103.8	62.267	138.07	324.26	15.24	6.096

Table 6-16
PSD Class I SO_2 Inventory

Name	Model ID	LAM-X (km)	LAM-Y (km)	Base El. (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)
PSD Increment Expanding									
Cameo Station	CameoBse	141.295	342.308	1463.0	-48.620	12.65	416.5	2.29	45.72
San Juan Unit 1	SJGS1	136.0993	88.1943	1614.9	-589.503	121.92	317.59	18.29	6.096
San Juan Unit 2	SJGS2	136.0993	88.1943	1614.9	-592.130	121.92	317.59	18.29	6.096
Four Corners Unit 1	4C1	132.5486	76.2073	1615.0	-72.510	76.20	327.59	18.29	5.36
Four Corners Unit 2	4C2	132.5486	76.2073	1615.0	-79.036	76.20	327.59	18.29	5.36
Four Corners Unit 3	4C3	132.6197	76.1436	1615.0	-86.247	76.20	327.59	31.63	4.36
Four Corners Unit 4	4C4	132.9928	75.8145	1615.0	-982.547	115.82	333.15	23.89	8.69
Four Corners Unit 5	4C5	132.9928	75.8145	1615.0	-972.085	115.82	333.15	18.29	8.69

Figure 6-13 PSD Class I SO_2 Source Locations

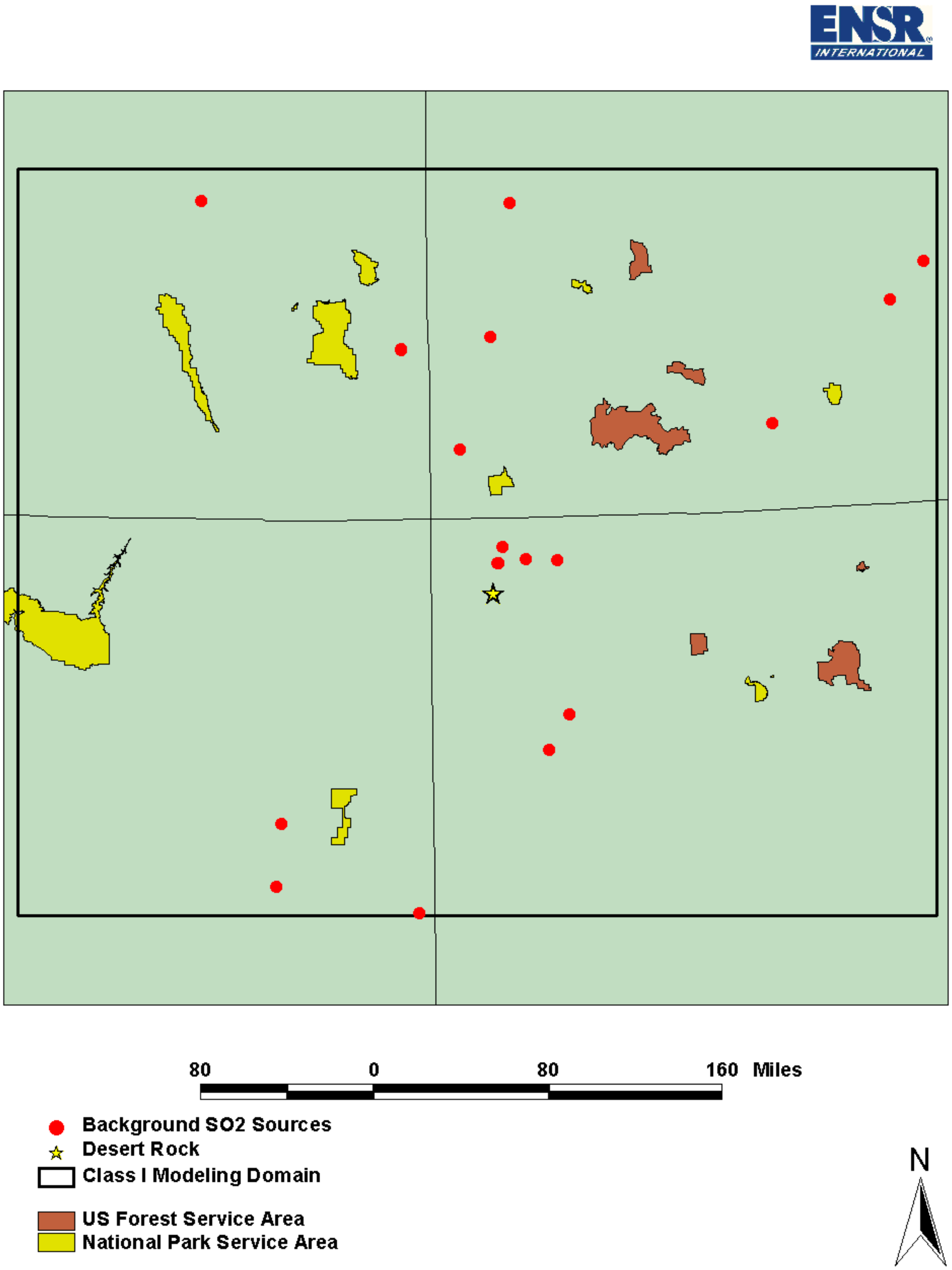

Table 6-17a
PSD Class I SO_2 Cumulative Modeling Results (FCPP Expansion Only)
Over 3 Years (2001-2003)

Class I Area	High-Second High (μg/m³)	
	3-hour [1]	24-hour
Arches NP	2.593	0.668
Bandelier NM	8.724	1.691
Black Canyon of the Gunnison NM	10.357	3.471
Canyonlands NP	6.460	2.159
Capitol Reef NP	2.230	0.594
Great Sand Dunes NM	10.844	2.013
La Garita WA	4.481	0.800
Mesa Verde NP	13.700	1.242
Pecos WA	5.486	1.444
San Pedro Parks WA	9.174	2.292
Weminuche WA	4.980	0.926
Wheeler Peak WA	3.712	0.782
PSD Increment	**25**	**5**

1. SO_2 3-hour results based on an emission rate of 0.09 lb/MMBtu to account for short-term variability. Emissions levels could be much greater and still not cause an increment exceedance.

Table 6-17b
PSD Class I SO_2 Cumulative Modeling Results (FCPP and SJGS Expansion)
Over 3 Years (2001-2003)

Class I Area	High-Second High (μg/m³)	
	3-hour [1]	24-hour
Arches NP	2.593	0.661
Bandelier NM	8.724	1.691
Black Canyon of the Gunnison NM	10.348	2.945
Canyonlands NP	6.410	2.093
Capitol Reef NP	2.203	0.561
Great Sand Dunes NM	4.959	1.944
La Garita WA	4.457	0.778
Mesa Verde NP	5.530	0.924
Pecos WA	5.486	1.444
San Pedro Parks WA	9.174	2.292
Weminuche WA	4.703	0.926
Wheeler Peak WA	3.712	0.782
PSD Increment	**25**	**5**

1. SO_2 3-hour results based on an emission rate of 0.09 lb/MMBtu to account for short-term variability. Emissions levels could be much greater and still not cause an increment exceedance.

6.5.4 Regional Haze Impacts

Results of the regional haze impacts from the proposed project are provided in Tables 6-18a and 6-18b. The results are presented in terms of the change in light extinction from natural background extinction as provided in the FLAG (2000) guidance. These results are supplemented by several refinements in the regional haze impacts, as follows:

- A relative humidity cap of 95%.
- The f(RH) curves adopted by EPA (2003) are used.
- The contribution to natural background extinction by airborne salt particles, which are ignored by FLAG, is considered. Although the area in question is removed from the Pacific Ocean, there are plentiful sources of salt aerosols in the West from surface salt deposits and flats, as well as salt lakes. The general procedures used in the determination of the salt concentration (a hygroscopic particulate component), are described in Appendix F of Attachment 4 (Modeling Protocol). The concentrations of airborne salt particles were obtained from IMPROVE measurements available at most of the PSD Class I areas, and are listed in Table 6-19.

The regional haze modeling results in Table 6-18b (which incorporate reasonable and technically defensible refinements to FLAG) indicate that there are relatively few days with modeled visibility extinction changes above 10% of natural background. A thorough review of the weather conditions on these days indicates that all of them can be documented as being associated with one or more of the following natural interferences to visibility:

- Occurrences of rain, snow, fog, etc.;
- Reduced visibility measurements at nearby representative airports;
- Cloud cover and/or elevated relative humidity at night, which would tend to preclude star-gazing activities.

The FLAG procedure for computing regional haze impacts relies upon 24-hour averages because the National Acid Precipitation Assessment Program study that formed the basis for visibility extinction in "natural conditions" relies upon daily particulate concentration measurements. This reliance upon daily averages (accounting for all 24 hours) has been verbally communicated to ENSR by the National Park Service on several occasions. The role of humidity in altering the natural visibility extinction is already part of FLAG in the form of the f(RH) relationship, which is applied on an *hourly basis* before the daily average is computed in CALPOST. However, the FLAG procedures, acknowledged by the National Park Service (Gebhart, 2004) as being a "screening procedure", have neglected to account for *the additional effects* on natural background extinction that are mentioned above. Techniques such as "MVISBK Option 7" in the CALPOST post-processor to CALPUFF do attempt to account for the additional effects precipitation and fog effects as observed at airports, but do not account for information available from additional data sources such as transmissometer measurements and due to cloud cover at night. The procedures used here, as documented in Appendix B in Attachment 4, supplement the MVISBK = 7 option as follows:

- A more mathematically appropriate manner in computing the daily average of hourly ratios (of source-caused extinction to natural extinction) is provided in the form of a geometric mean. This also improves upon the problem (for all current MVISBK options in CALPOST) that an outlier extinction value for a single hour can significantly and inappropriately affect the daily ratio.

- The difficult requirement to estimate the exact natural extinction that is needed in the MVISBK=7 option calculation is avoided by making the reasonable assumption that for hours of natural impairment, the perceptibility of the source-caused extinction is essentially zero. This assumption works well with the use of the geometric mean of hourly ratios technique.

Table 6-18a
FLAG Results Without Refinements

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change
Arches NP	2003	1	0	5.64
Bandelier NM	2001	9	2	17.97
Black Canyon of the Gunnison NM	2003	2	0	9.42
Canyonlands NP	2003	2	1	12.98
Capitol Reef NP	2002	2	0	6.80
Grand Canyon NP	2002	2	1	10.81
Great Sand Dunes NM	2002	5	0	7.59
La Garita WA	2001	1	0	5.67
Mesa Verde NP	2002	12	2	12.50
Pecos WA	2001	10	1	11.45
Petrified Forest NP	2002	3	1	12.29
San Pedro Parks WA	2001	14	4	27.35
Weminuche WA	2002	25	2	15.18
West Elk WA	2001	1	0	7.91
Wheeler Peak WA	2003	1	0	9.42
Worst-case year: FLAG f(RH) Values, MVISBK=2, RHMAX=98%				

Table 6-18b
FLAG Results With Refinements

Class I Area	Worst-Case Year	No. of Days Over 5%	No. of Days Over 10%	Max % Change After Preliminary Refinement	Max % Change After Additional Refinement
Arches NP	2003	0	0	4.21	--
Bandelier NM	2001	7	1	11.98	<5
Black Canyon of the Gunnison NM	2001	1	0	6.63	<5
Canyonlands NP	2003	1	0	8.39	<5
Capitol Reef NP	2002	2	0	6.93	<5
Grand Canyon NP	2002	1	0	8.36	<5
Great Sand Dunes NM	2002	3	0	7.40	<5
La Garita WA	2001	0	0	4.83	--
Mesa Verde NP	2002	7	0	8.90	<5
Pecos WA	2001	6	0	7.74	<5
Petrified Forest NP	2002	2	0	9.34	<5
San Pedro Parks WA	2001	10	1	17.00	<5
Weminuche WA	2002	5	0	7.16	<5
West Elk WA	2001	1	0	7.58	<5
Wheeler Peak WA	2003	1	0	5.17	<5

Worst-case year: EPA f(RH) Values, MVISBK=2, RHMAX=95%, Includes Salt Aerosol

All days over 5% with preliminary refinements subsequently determined to be associated with natural obscuration. When these days are addressed (see Attachment 7), remaining days have less than a 5% change of extinction and no further analysis is required.

All days with modeled extinction changes over 5% (with the use of refinements used in the Table 6-18b results) were associated with natural obscuration. With the application of these reasonable refinements to FLAG (described in more detail in Attachment 7), for the days with a reported extinction change over 5% after the initial refinements (Table 6-18b) we find that there are no days left with an extinction change greater than 5%. (Details with documentation for each day that was reviewed are provided with the modeling data archive.) Therefore, we conclude that the proposed project does not cause an adverse visibility impact in any PSD Class I area, and that no further modeling analysis for visibility impacts is required.

Table 6-19
Annual Average Salt Concentrations in PSD Class I Areas (from IMPROVE Data)

PSD Class I Area	Annual Average NaCl Conc. ($\mu g/m^3$)
Arches NP	0.065
Bandelier NM	0.095
Black Canyon of the Gunnison NM [1]	0.086
Canyonlands NP	0.113
Capitol Reef NP	0.098
Grand Canyon NP – Hance	0.117
Great Sand Dunes NM	0.099
La Garita WA [1]	0.086
Mesa Verde NP	0.117
Pecos WA [2]	0.095
Petrified Forest NP	0.150
San Pedro Parks WA	0.114
Weminuche WA	0.086
West Elk WA [1]	0.086
Wheeler Peak WA	0.100
1. Used data from Weminuche WA 2. Used data from Bandelier NM	

6.5.5 Sulfur and Nitrogen Deposition Analysis

Results of the sulfur and nitrogen deposition analysis due to emissions from the proposed source are provided in Table 6-20. There are no published thresholds for acidic deposition for the PSD Class I areas in which acidic deposition impacts will be addressed. The deposition results are provided here for evaluation by the FLMs. However, it is noted that the United States Department of Agriculture Forest Service (http://www.fs.fed.us/r6/aq/natarm/r8/r8_psd_screen.pdf, Appendix A) indicates that the minimum detectable level for measuring an increase in wet deposition of sulfates or nitrates is 0.5 kg/ha/yr. For conservatism, the Forest Service recommends a significance level of one tenth of this minimum detectable level, or 0.05 kg/ha/yr. In addition, the FLM has also recently developed a Deposition Analysis Threshold (DAT) for nitrogen (also used for sulfur) of one tenth of the significance level, or 0.005 kg/ha/yr (FLAG, 2001). This value is to be used as a trigger for further FLM analysis, rather than as an adverse impact threshold (Porter, 2004). Values shaded in Table 6-20 are above the DAT levels, but are all below the 0.05 kg/ha/yr significance levels mentioned above.

Table 6-20
Maximum Total Nitrogen Deposition Over Three Years (2001-2003)

PSD Class I Area	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)	Screening Threshold Value (kg/ha/yr)
Arches NP	1.74E-03	3.47E-03	5.00E-03
Bandelier NM	6.34E-03	1.59E-02	5.00E-03
Black Canyon of the Gunnison NM	2.34E-03	4.48E-03	5.00E-03
Canyonlands NP	2.63E-03	5.71E-03	5.00E-03
Capitol Reef NP	1.18E-03	2.73E-03	5.00E-03
Grand Canyon NP	8.36E-04	1.54E-03	5.00E-03
Great Sand Dunes NM	3.19E-03	6.31E-03	5.00E-03
La Garita WA	4.95E-03	9.24E-03	5.00E-03
Mesa Verde NP	8.61E-03	2.15E-02	5.00E-03
Pecos WA	4.92E-03	1.14E-02	5.00E-03
Petrified Forest NP	1.71E-03	3.14E-03	5.00E-03
San Pedro Parks WA	7.95E-03	1.98E-02	5.00E-03
Weminuche WA	8.10E-03	1.67E-02	5.00E-03
West Elk WA	2.37E-03	4.32E-03	5.00E-03
Wheeler Peak WA	3.75E-03	7.44E-03	5.00E-03

6.5.6 Lake Acid Neutralizing Capacity Analysis

Sulfur and nitrogen deposition can impact lakes in and near Class I and sensitive Class II areas. The Forest Service provided ENSR with a screening methodology to calculate the change in lake acid neutralizing capacity (ANC) from a baseline value at several lakes within the modeling domain. The screening procedure used for this analysis is documented in Appendix G of Attachment 4.

Table 6-21 lists the lakes in the analysis and their monitored baseline acid neutralizing capacity in units of micro-equivalent per liter (μeq/l). The threshold values for change in ANC are as follows:

- If the baseline ANC > 25, up to a 10% change in ANC is allowed
- If the baseline ANC < 25, up to a 1 ueq/l change in ANC is allowed
- If the baseline ANC < 0, “no change” in ANC is allowed

The results of the calculations are also presented in Table 6-21, and reflect the average increase over the three years modeled in micro-equivalents per liter or percent change of ANC. The results show little to no increase in the acid neutralizing capacity of these lakes.

Table 6-21
Baseline Acid Neutralizing Capacity and Potential Changes for Lakes Within the Modeling Domain

Wilderness Area	Lake Name	UTM N	UTM E	Baseline ANC (µeq/l)	ANC Change (%)	Average ANC Change (µeq/l)
La Garita	Small Lake Above U-Shaped Lake	4,201,000	336,200	53.7	0.5	N/A
	U-Shaped Lake	4,200,850	336,500	65.3	0.4	N/A
South San Juan	Glacier	4,124,500	359,300	63.4	1.0	N/A
	Lake South of Blue Lakes	4,120,800	355,450	19.8	N/A	0.2
Weminuche	Big Eldorado	4,176,679	275,801	27.7	0.4	N/A
	Little Eldorado	4,176,833	275,489	-2.4	N/A	0.2
	Lower Sunlight	4,168,037	272,111	79.8	0.6	N/A
	Upper Grizzly	4,166,642	271,756	24.3	N/A	0.4
	White Dome	4,176,293	275,042	2.3	N/A	0.3
West Elk	S. Golden	4,294,000	310,300	111	0.1	N/A

6.6 Additional Impact Analyses

The PSD regulation requires that additional analyses be performed when assessing the impacts of a proposed project. These additional analyses include an evaluation of potential impacts caused by secondary emissions from growth caused by the project and an analysis of impacts to soils and vegetation that have economic value. In addition to these PSD required analysis, EPA requested that Steag provide an analysis of the Project's potential for impact to ozone in the area and also a review of potential impacts to biological and cultural resources. These analyses are provided in this Section.

6.6.1 Growth Analysis

A growth analysis examines the potential emissions from secondary sources associated with the proposed project. While these activities are not directly involved in project operation, the emissions can reasonably be expected to occur. For the proposed Desert Rock Energy Facility, secondary emissions will be associated with:

- coal processing and handling activities associated with the coal supply, and
- the project workforce.

The secondary emissions associated with the Project are not expected to be substantial when compared to direct emissions during either construction or operation of the facility. As discussed below, the emissions associated with the coal supply system will occur during plant operation and will be primarily due to road dust from coal haul truck operation on unpaved roads. There will be little new growth in the area due to the small work force (200-225 employees) expected during plant operation. The emissions associated with the workforce will be primarily the result of motor vehicle exhaust emissions associated with the commute of workers to and from the plant site.

The emissions associated with the coal operation are expected to be localized in the immediate area of the mine. The emissions due to worker commute are expected to be distributed over a two-county area of San Juan and McKinley counties with limited impact at any given location. Based on this analysis, we conclude that there will be little impact beyond the local area surrounding the Desert Rock Energy Facility due to secondary emission sources.

6.6.1.1 Secondary Emissions Associated with Coal Supply

Coal for the Desert Rock Energy Facility will be purchased under a contract with BHP Billiton, the operators of the Navajo Mine. The design specifications for the coal will require BHP Billiton to blend coal from about five of the Navajo Mine coal seams.

Coal will be mined from an open pit and transported to the crushing plant by off-road mining trucks. The run-of-mine coal will be crushed and blended to meet the design specification of the proposed facility. The blended coal will be fed onto a conveyor and transported to the coal bunkers of the proposed facility.

The coal handling facility owned and controlled by Steag will store approximately a 30-day supply of blended coal on site as a strategic reserve. For normal operations of the facility this coal will remain untouched. The mine will also maintain, on their site, a coal storage area with run-of-mine coal with several days supply.

These coal preparation activities will be under the control of BHP Billiton and will likely be conducted in an area south of the current mining operations and east and north of the proposed power generation facility. The mining, storage and blending activities associated with providing coal for the facility are secondary activities caused by the power plant operation.

BHP Billiton has not provided details on how they will supply the coal to Steag. Based on typical operations of this sort, the fugitive PM_{10} emissions associated with the coal supply system are expected to be on the order of 15 tpy from the coal handling activities and on the order of 50 tpy from travel on unpaved roads to haul coal from the mine site to the crushing plant. These emissions will likely be controlled by industry-standard fugitive dust control measures. These fugitive dust emissions will be very localized to the mine and blending facility area. The emissions will be associated with non-buoyant plumes released from ground level or near-ground activities. The dust released is unlikely to travel significant distances. Given the rural location for the power plant site and the limited transport distances expected of the fugitive PM_{10} emissions, the impact is expected to be minor from these secondary fugitive emissions associated with the coal supply operation.

6.6.1.2 Emissions Due to Workforce Travel

The Desert Rock Energy Facility is proposing to locate in San Juan County, New Mexico. During construction, the project is expected to employ about 800 workers, although the workforce may be up to 3,000 workers during peak construction periods. After start of operations, there will be approximately 200-225 employees.

The workers for the plant (both construction and operations) are primarily expected to come from San Juan County and adjoining McKinley County. It is expected that approximately 10% of the workforce will come from rural areas within the Navajo Nation. Most workers (~60%) will commute approximately 30 miles from the Farmington and Shiprock areas (San Juan County) while the remainder will commute approximately 75 miles from Gallup (McKinley County) and Window Rock (Apache County, Arizona). The Navajo Nation requires preferred employment of local people, hence many of the workers are expected to come from rural areas in the Navajo Nation.

The estimated 2002 population of San Juan and McKinley counties was 120,400 and 74,000 persons. The basic construction workforce of 800 persons is less than 0.4% of the population from which the labor pool will be drawn. Over the past six years, San Juan and McKinley Counties have consistently had unemployment above the statewide average. From published New Mexico Department of Labor statistics, the unemployment rate in San Juan and McKinley Counties in 2002 was 6.7% (3,500 persons) and 6.1% (1,600 persons), respectively, compared with the statewide total of 5.4%. While only a portion of the unemployed persons in the two counties would be qualified for construction or operation jobs at the power plant, the number of unemployed workers in the two counties in 2002 is slightly less than two times the 3,000 workers on site during the peak periods and more than 6 times the daily average of 800 workers during most of the construction period. As many of the construction workers during peak periods will be transient workers hired or brought in by subcontractors, they may cause local short-term demand for services in area hotels and restaurants but will not contribute to permanent growth in the area due to their transient nature. Negligible growth is expected for the operation phase given the small number of operational workers (225) in a two-county region of nearly 200,000 persons.

Based on current unemployment levels, the requirement by the Navajo Nation for preferred employment for local persons, and the expectation that a significant number of workers will come from the existing employment pool in the area, population growth associated with the proposed project is expected to be small.

Consequently, secondary emission increases associated with the project workforce will be due primarily to worker commuter trips. As approximately 30% of the workers will commute from Gallup (approximately 75 miles) and 60% from Shiprock and Farmington (approximately 25 miles), an average commute on the order of 40 miles is a reasonable estimate. For construction, assuming 800 employee commute trips per day of 40 miles each way, the typical daily commute vehicle miles traveled (VMT) will be approximately 64,000 vehicle-miles per day. PM_{10}, VOC and NO_x from this traffic might be on the order of 15 tpy for the three-year construction period. For operations, the VMT will be much lower, less than approximately 18,000 vehicle-miles per day, or about 5 tpy of PM_{10}, VOC and NO_x.

Given the rural nature of the two-county region, vehicle emissions associated with the project workforce travel will likely be spread out over a substantial part of the two-county area, an area of over 8,500 square miles. Consequently, the impacts of any emissions will not be concentrated but rather will be dispersed throughout a large area, thus limiting local impacts in the largely rural counties.

6.6.2 Impacts on Soils and Vegetation

PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, and sensitive types of soil. Evaluation of impacts on sensitive vegetation were performed by comparing the predicted impacts attributable to the Project with the screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA 1980).

The results of this analysis are given in Table 6-22. As shown in the table, all impacts are modeled to be well below the screening levels. Most of the designated vegetation screening levels are equivalent to or less stringent than the NAAQS and/or PSD increments, therefore satisfaction of NAAQS and PSD increments assures that sensitive vegetation will not be impacted.

Table 6-22
Screening Concentrations for Soils and Vegetation

Pollutant	Averaging Period	Screening Concentration (μg/m³)	Predicted Concentration (μg/m³)
SO_2	1-Hour	917	384.9
	3-Hour	786	130.6
	Annual	18	0.65
NO_2	4-Hours [1]	3,760	87.2
	1-Month [2]	564	24.4
	Annual	94	0.62
CO	Weekly [1]	1,800,000	427.5

Source: "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". EPA 450/2-81-078, December 1980

1. Modeled with the 3-hour Averaging Time
2. Modeled with the 24-hour Averaging Time

6.6.3 Impacts on Ozone Concentrations

The New Mexico Environmental Department has recently conducted a comprehensive photochemical modeling study (using CAMx) of the projected ozone concentrations in the Farmington, NM area. The 2004 study, found at www.nmenv.state.nm.us/ozonetf, included new sources, such as the proposed Steag project. The results of the study indicated that:

- Compliance with the 8-hour ozone standard is demonstrated for 2007 and 2012
- Ozone concentrations are expected to decrease slightly during the period leading up to 2012
- Background ozone (transported from long distances) is an important contributor to elevated ozone levels
- Biogenic emissions contribute more to ozone formation that anthropogenic emissions
- Source categories of electric utilities, oil and gas sources, area sources, and mobile sources each contribute about equally to the formation of ozone in the Farmington area.

Based on the results of this study, which accounted for the Project emissions in the region, it can be concluded that the Desert Rock Energy Facility will not cause or contribute to an exceedance of the ozone AAQS in the region.

6.6.4 Endangered Species and National Historic Preservation Acts

The proposed project requires Federal permits and an agreement to use trust lands of the Navajo Nation. As a result, the project requires review under and compliance with the National Environmental Policy Act (NEPA) (42 U.S.C. 4321-4347) and its implementing regulations. Under NEPA, the protection of environmental resources will be assessed and the potential impacts of the Project will be determined. This work will include a review under the Endangered Species Act (ESA) (7 U.S.C. 136; 16 U.S.C. 460 et seq.) and Section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations (Protection of Historic Properties, 36 CFR 800). Steag is prepared to work with the Bureau of Indian Affairs (BIA), as the lead Federal agency under NEPA, in complying with all applicable regulations. A discussion of the Project reviews to date under the ESA is contained in Attachment 8 and work related to the NHPA is contained in Attachment 9 of this application.

6.7 Summary of Air Quality Modeling Results

Dispersion modeling of the air quality impacts of the proposed Desert Rock Energy Facility has been completed. The results are summarized below.

6.7.1 PSD Class II results

- The Project impacts are above PSD Class II significance levels for a limited area around the facility (about 11 km for SO_2 and 1.7 km for PM_{10}). The project has insignificant impacts for CO and NOx.

- The peak impacts from the facility are located very close to the fenceline (within 1 km in most cases). These impacts are likely due to the emergency generator or auxiliary boilers that do not run continuously.

- The PSD increment consumption due to the facility emissions is well within PSD Class II increments. The cumulative modeling analysis shows compliance with PSD Class II increments and the NAAQS.

- The SO_2 3-hour and 24-hour impacts are 19% and 12% of the PSD Increments and are located between 1.0 km and 1.5km from the main stack. The PM_{10} 24-hour and annual impacts are 29% and 12% of the PSD Increments and are located within 1.0 km of the main stack.

- The SO_2 3-hour and 24-hour impacts are 16% and 15% of the NAAQS and are located 11 km from the main stack. Distant impacts from the Four Corners Power Plant and the San Juan Generating Station are likely contributors to this total. The PM_{10} 24-hour and annual impacts are 32% and 39% of the NAAQS and are located within 1 km of the main stack.

- There are no modeled significant impacts from the proposed project in areas beyond the Navajo Nation, including New Mexico lands and the Ute Mountain range to the north.

- Impacts on numerous distant PSD Class II areas (located beyond 50 km) show increment consumption below significance limits. Steag has provided regional haze and deposition results for informational purposes, since PSD Class I limits are not applicable in Class II areas. No further modeling analysis for these distant areas is needed.

6.7.2 PSD Class I Results

- The project impacts are above PSD Class I significance levels for SO_2 in a number of areas (including three PSD Class II areas that have special Colorado designation as Class I for SO_2). The project has an insignificant impact for NO_2 and PM_{10} increment.

- The project's impact is a small fraction of the total increment (slightly over 20% for SO_2). The cumulative analysis shows that the project does not cause or contribute to a PSD Class I increment violation. The 3-hour and 24-hour SO_2 impacts are 41% and 69% of the PSD Increments, respectively, for the cumulative modeling with Four Corners Power Plant increment expansion. The 3-hour and 24-hour SO_2 impacts are 41% and 59% of the PSD Increments, respectively, for the cumulative modeling when accounting for the Four Corners Power Plant and San Juan Generating Station increment expansion.

- The project's impacts on sulfur and nitrogen deposition are higher than the very low DAT levels that trigger additional review in a few areas. The United States Department of Agriculture Forest Service web site (http://www.fs.fed.us/r6/aq/natarm/document.htm) indicates that the minimum detectable level for measuring an increase in wet deposition of sulfates or nitrates is 0.5 kg/ha/yr. For conservatism in judging impacts, the Forest Service recommends a deposition significance level of one tenth of this minimum detectable level, or 0.05 kg/ha/yr. All of the impacts modeled for the proposed plant are below this significance level, and include a component of ammonia salts that are not acidic. Steag therefore concludes that the proposed project does not adversely impact deposition. This information is being provided to the FLMs for their review.

- The project's impacts on regional haze are higher than insignificance thresholds of 5% change to background extinction with the use of the FLAG screening procedures. A number of refinements to FLAG are presented, and the results show that there are no remaining days over the three years modeled that exceed the threshold of a 5% change. A review of those days indicates that they can be documented as being associated with one or more of the following natural interferences to visibility:
  - Occurrences of rain, snow, fog, etc.;
  - Reduced visibility measurements at nearby representative airports;
  - Cloud cover and/or elevated relative humidity at night, which would tend to preclude star-gazing activities.

In conclusion, all potential impacts to air quality and air quality related values due to the Desert Rock Energy Facility are expected to be within acceptable levels.

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